Analysis Related to Merchant Plant Siting in South Carolina

PREPARED FOR

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CHAPTER ONE: INTRODUCTION

STUDY OVERVIEW

ICF Resources Incorporated (ICF) was engaged by the State of South Carolina to provide an independent expert opinion of issues relating to merchant plant siting in South Carolina. The goals of this analysis, as stated in the original request for proposals are to:

- Interpret the original intent of the Power Plant Siting Act versus its present interpretation relative to merchant plants
- Consider the existence of contractual obligation by merchant plants prior to construction
- Consider the impact of merchant plant development on the transmission system
- Consider the impact of merchant power plant development on natural gas supply/demand and pricing
- Consider the impact on future siting of generation facilities by incumbent suppliers given the development of merchant plants

The analysis initiative stems from a concern regarding an oversupply of power plants, especially merchant facilities and their impact on consumers and incumbent utilities. The specific goals were encompassed in a series of distinct tasks that will be the focus of this report.

- Task A: Review merchant plant siting policies and impact
- Task B: Review the existence of contractual obligations on merchant plants prior to construction
- Task C: Review the impact on the transmission system
- Task D: Review the impact on the supply/demand and pricing of natural gas
- Task E: Review the potential impact on siting of future generation by incumbent suppliers

The remainder of this report will focus on addressing these issues as well as providing additional background information on the current state of the electric industry in South Carolina. The conclusion of this report will provide recommendations on additional areas of focus or modification to the Utility Facility Siting and Environmental Protection Act.

The organization of this report is designed to first provide readers with critical background on the United States electric industry, both from a historical context and based on important issues facing the market in the future.

A comparison of siting requirements across several states and regional organizations is then provided.

We then concentrate specifically on the South Carolina energy markets providing background on the current electric market in Chapter Four, the Natural Gas Market in Chapter Five, and the Transmission Market in Chapter Six.

ICF prepared scenario analysis of the South Carolina Electricity market to provide informed analysis on the impact of alternate forward events on the generators and ratepayers in the state. The assumptions for this analysis are described in Chapter Seven, while results are provided in Chapter Eight.

The final recommendations for siting power plant facilities based on qualitative and quantitative analysis of the South Carolina market are provided in Chapter Nine.

CHAPTER TWO: THE SOUTH CAROLINA UTILITY FACILITY AND ENVIRONMENTAL PROTECTION ACT

This chapter gives a summary of the Power Plant Siting Act and the process of power plant siting in South Carolina compared to other select states in the U.S. We further provide an overview of the status of the electric industry in South Carolina compared to other states in the South East.

HISTORY OF THE UTILITY SITING AND ENVIRONMENTAL PROTECTION ACT

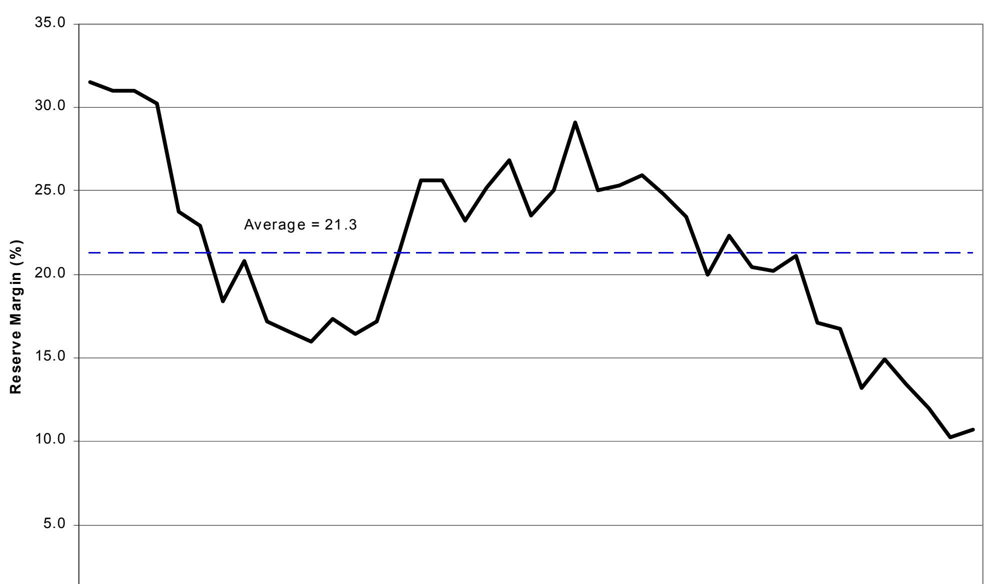
Establishment of the Act – National Industry Trends Through the Early 1970s

The South Carolina Utility Facility Siting and Environmental Protection Act was introduced in 1971 and became effective in 1972. This occurred during a period of change for the United States electric utility industry. Prior to the act, the electric utility industry in the US experienced rapidly growing demand and consistently falling electricity prices. Construction of new power plants was relatively uncontroversial.

During this same time, demand grew so quickly that utility reserve margins were experiencing a significant rate of decline resulting in concerns about overall system reliability. Indeed, the National Electricity Reliability Council (NERC) was established in 1965 as a result of significant blackouts in the Northeast in 1965.

However, significant changes that were precursors to stricter cost and environmental standards began appearing in the late 1960s.

Figure 2.1: Historical Reserve Margins in U.S. (1960-2000)



Source: 1960-1999; EEI, Statistical Yearbook of Electric Utility Industry. 2000; NERC 2001 ES&D. Reserve Margin calculated as : (Capability - Peak Demand) / Capability *100

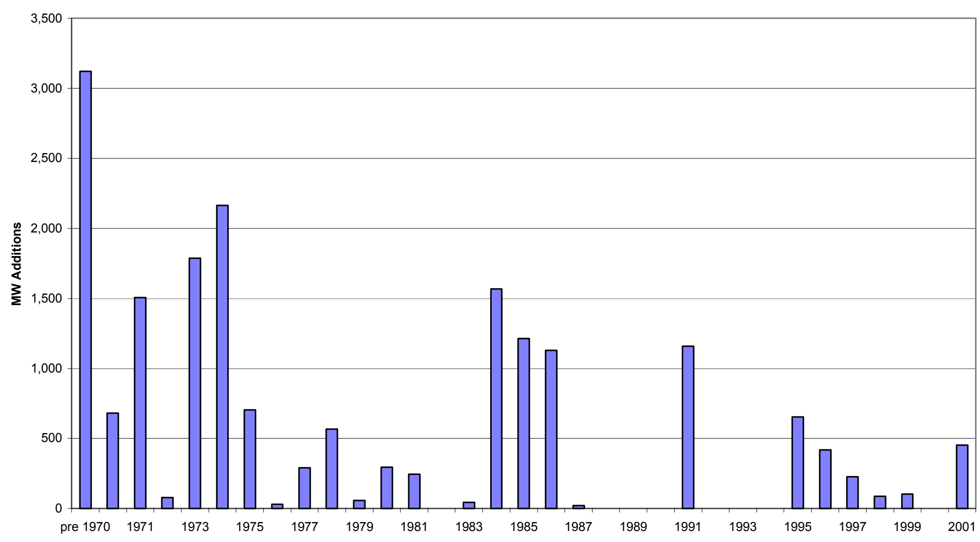
New nationwide concerns about utility capacity expansion included focus on:

- **Environmental Quality** – On the federal level, the 1969 National Environmental Policy Act (NEPA) required new plants to file environmental impact statements and the Clean Air Act (1970) was key in increasing environmental compliance costs.
- **Generation Cost** – After decades of falling generation costs, increasing thermal efficiencies and greater economies of scale, the generation situation deteriorated for conventional steam based technologies. There were large cost overruns in nuclear power plants and the growth in economies of scale stalled. Also, thermal efficiencies plateaued for steam units. This was significant since new plants, rather than lowering rates began to raise them.
- **Electricity Demand** – Rapidly rising electricity demand growth in the 1950s and 1960s associated with economic growth, air conditioning, new appliances, etc. began to slow. This was accompanied by growing inflation and economic problems in the early 1970s, and saturation in some end uses.
- **Lead Times** – Plant sizes rose dramatically in the 1960s and early 1970s as did plant lead times. This exacerbated the effects of unexpected demand growth slow downs in terms of creating more excess capacity. By the mid-1970s U.S. average reserve margins had skyrocketed.

In light of these trends, it is not surprising that there was increased consideration of need, environmental impacts and effects on ratepayer costs. Many states enacted similar statues to the South Carolina Utility Siting Act and Environmental Protection Act at the same time.

The South Carolina Siting Act was highly supported by the state utilities as well as the Public Service Commission. At the time it was established, it was thought that the Federal government would further intervene to establish standards and practices for new plants. In order to maintain a level of control within the state, the Siting Act was enacted.

Figure 2.2: South Carolina Annual Capacity Additions



The Act itself was established at a time when the greatest capacity expansion was experienced in South Carolina- utilities were implementing major and costly expansions of generating capacity as shown. Capacity additions in 1973 and 1974 alone totaled nearly 4 GW or over 40 percent of the total capacity installed to date in South Carolina. Much of this capacity was not directly subject to the Siting Act which exempted facilities that had begun construction one year after the effective date of January 1, 1972.

At the time, the South Carolina utilities had ambitious capital expansion programs including several major nuclear additions. In addition, inflation was increasing significantly and compounded the effects of rising investment costs. In general, utilities faced financial difficulties in justifying and meeting these increased costs. Once these units were added to the rate base, the ratepayers were faced with substantial rate increases and the main issue of the Siting Act - justifying capacity additions – came to the forefront.

Continued Electric Industry Trends – Mid 1970s – 1980s

At first, increased state regulation of new power plant additions focused in on need and on the appropriateness of large baseload plant options (e.g., nuclear and coal). This often led to careful attention to electricity demand growth forecasting. However by the late 1970s, new trends began to shift the focus of state regulators to natural gas and demand side options. In many jurisdictions, there was increased interest in non-utility power.

By the mid-1970s, the energy crisis led to growing interest in energy efficiency and conservation. This combined with a general movement to deregulate industries (e.g., airlines, railroads, telecommunications, trucking). In the case of power, this led to interest in non-utility cogeneration. In 1978, Congress enacted the Public Utilities Reform Policy Act (PURPA) which mandated utility purchase of locally generated third party cogenerated power at the utility's avoided costs. The goal was to create a market for cogenerated power without having to open utility electric transmission lines to third parties.

Also, the Fuel Use Act of 1979 made it impossible for utilities to build baseload gas or oil plants. This occurred at just about the same time as technological improvements in gas generation technology, falling oil and gas prices and emphasis on lower environmental impacts which made gas power plants increasingly attractive. Cogenerators filled the void and built gas power plants.

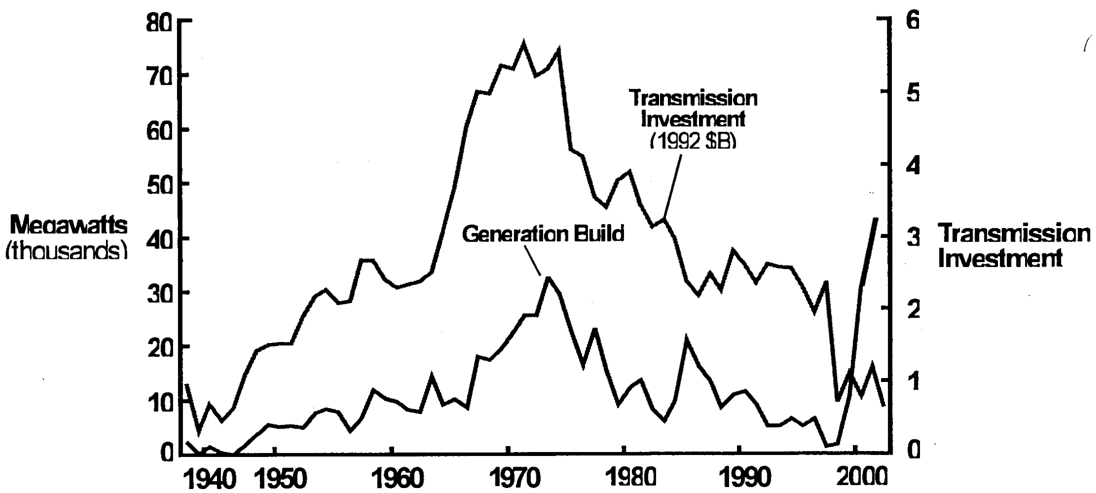
Lastly, inflation and rising costs made it difficult for many utilities to want to build new plants since electricity rates often did not keep pace with rising costs. By the late 1980s to early 1990s, most new plants added in the U.S. were owned by non-utility generators and most were gas-fired. This trend did not affect South Carolina as strongly as it did other states.

In many states, the potential for third party power further increased scrutiny of the need for integrated utilities to build their own new power plants. Many states added competitive bidding requirements to cogeneration and/or non-cogenerated power. Over time, these bidding processes became increasingly elaborate. Also, many states expanded need, environmental considerations, and customer impacts into Integrated Resource Plans (IRPs). The IRPs concentrated heavily on the consideration of new plant alternatives, need, and appropriateness of demand side versus supply side options.

During the late 1980s to early 1990s, the impacts of alternative build options on the electricity transmission systems were sometimes considered, but not as prominently as recently. Part of this was related to:

- New units were still primarily selling power under long-term contracts to single power companies which were expected to ensure electricity transmission adequacy.
- New gas-fired units were smaller than they are today and hence, less taxing on the transmission systems.
- There was less transparency in transmission due to lack of open access.
- There was more excess transmission capacity left over from expansion of line capacity in earlier periods; the extreme collapse in electricity transmission investment relative to generation investment had not yet occurred as shown.

Figure 2.3: Transmission Investment versus Generation Expansion



Also, relatively little emphasis was placed on the impact of new plants on the gas transmission system. This was primarily because units were generally baseload cogeneration units with long-term firm gas supply contracts. Secondarily, concern about gas was muted by:

- apparent success in federal deregulation of the gas industry
- federal eminent domain for gas lines facilitating infrastructure expansion
- successful “open season” consideration of new proposed lines leading to expansion
- the lower visibility of new gas lines due to their being nearly always underground
- lower costs of gas relative to power lines, and
- leftover gas capacity in many areas as gas demand in residential, and industrial areas only slowly recovered from pre-energy crisis peaks.

Deregulation – 1990s

The deregulation following the Energy Policy Act of 1992 and continuing till today has seen even greater changes with implications for state regulation. Recent trends have also seen a greater federal and regional role, and the implications for state regulation of need, cost and other issues are still being considered.

Key features of deregulation included:

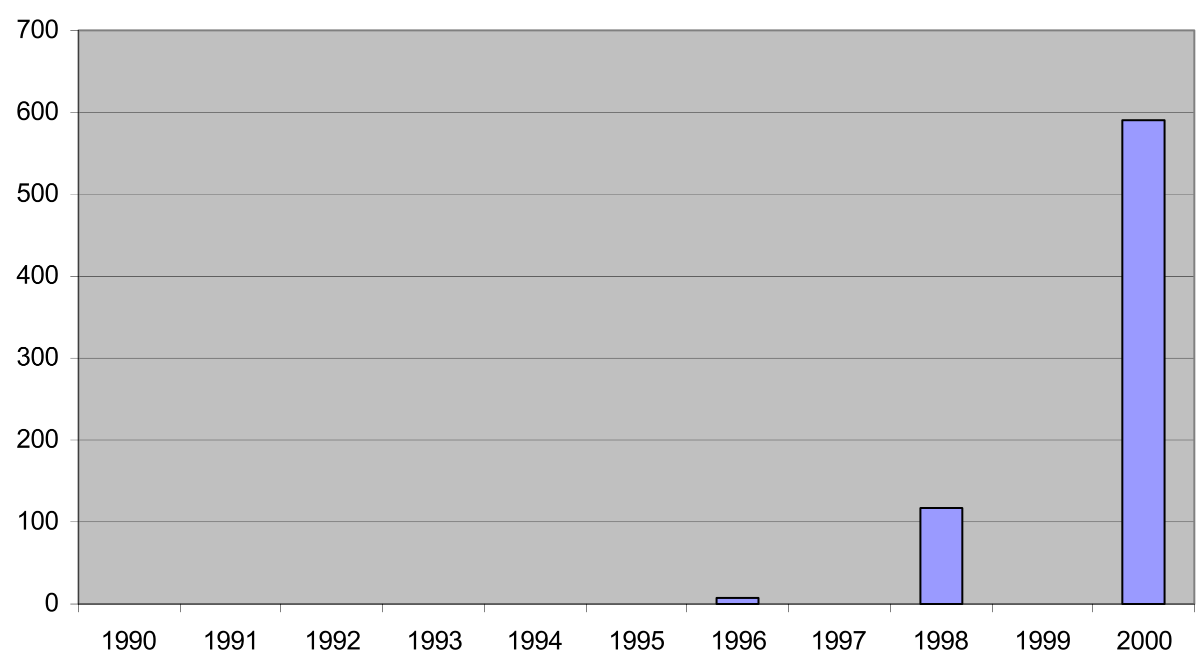
- **Merchant Plants** – Most plants built have had at least some capacity uncommitted to any buyer. Most lack long-term contracts (greater than 10 years), and hence, do not know whom they will be selling to and what transmission service will be needed. Also, the amount of capacity being added is very large. Between 1999 and 2004, nearly 200,000 MW will have been added on a system with a peak demand of only approximately 700,000 MW. Concerns have emerged as to whether support systems, especially power and gas transmission will be able to accommodate so fast and so large an expansion of generation.
- **Transmission Access** – The key event in the deregulation was the requirement that utilities provide open and comparable access to utility transmission lines under the aegis of FERC. This enabled companies to build plants without having to arrange power sales with one buyer, i.e., the local company since they could access distant buyers. Since FERC must decide what is open and comparable, the federal role in transmission increased greatly.
- **Transmission Hook-Ups for New Plants** – Transmission owners must provide non-utility merchant plants or any plant hook-ups to the grid on a non-discriminatory basis under FERC regulations. This is another example of growing FERC authority. Only states can block new plants.
- **Transmission Rights** – Allocation of available firm capacity is first come first serve in some cases. A merchant power plant could request long-term firm transmission supply from a utility on a transmission path, and receive that for a relatively low cost because the path has excess capacity. It could also occur that the next project even if it is an incumbent utility project could request the same service and have to pay more. This occurs because FERC policy mandates comparable access and allocation of incremental costs to new power plants as a means of insuring economic siting. This has led some state regulators to be concerned that merchant power plants, especially those serving out-of-state customers, could exhaust scarce transmission capacity and raise rates to in-state customers. It is also theoretically possible that the reverse could occur that merchant power plants built first could by paying for upgrades, and shifting power flows lower costs for projects later in the queue. The concern, however, has been disproportionately on the potential for higher costs since there is the perception of excess capacity built and paid for by ratepayers being exhausted by merchant power plants.
- **Transmission Tariffs** – Changes in tariffs are forthcoming affecting the competitiveness of generation wholesale power prices and inter-regional power flows. Overall, tariff boundaries are being reduced by FERC action.
- **Transmission Supply** – Deregulation has been associated with a dramatic collapse in transmission investment. One explanation is that often utilities had built transmission lines along with new plants, but as they withdrew from generation, leaving it to merchants, this activity stopped. This affects the entire grid since as demand grows congestion will likely increase. Also, the grid is highly integrated and multi-state with significant potential for developments in one area to unexpectedly affect others.
- **Competition** – FERC's role is increasing as it assumes responsibility for assuring competitive markets. Tariff changes are an example.
- **Utility Industry Organization** – Utilities have had to functionally unbundle transmission and FERC is encouraging sales of transmission assets. FERC is mandating regional multi-state, multi-utility transmission organizations to run the

grid. These regional transmission organizations will be regulated by FERC, though some role for states is expected.

- **Eminent Domain and State-Federal Coordination** – States control both generation and electricity transmission additions. This contrasts with the natural gas industry where FERC has eminent domain control for new gas pipelines. This is a key issue affecting coordination between state and federal entities.
- **Natural Gas Markets** – As mentioned, the country is experiencing the largest generation capacity expansion in its history for a six-year period. Essentially, all new units are non-utility natural gas-fired and few have firm gas supply. Stresses have occurred on gas transmission, especially in the west where it has dramatically raised gas prices.

Although merchant plant activity was robust throughout the country, South Carolina saw relatively less activity, as can be seen in the chart below.

Figure 2.4: NUG Capacity Additions (MW), South Carolina, 1990-2000



Source: Form EIA-860B, EIA, 2000

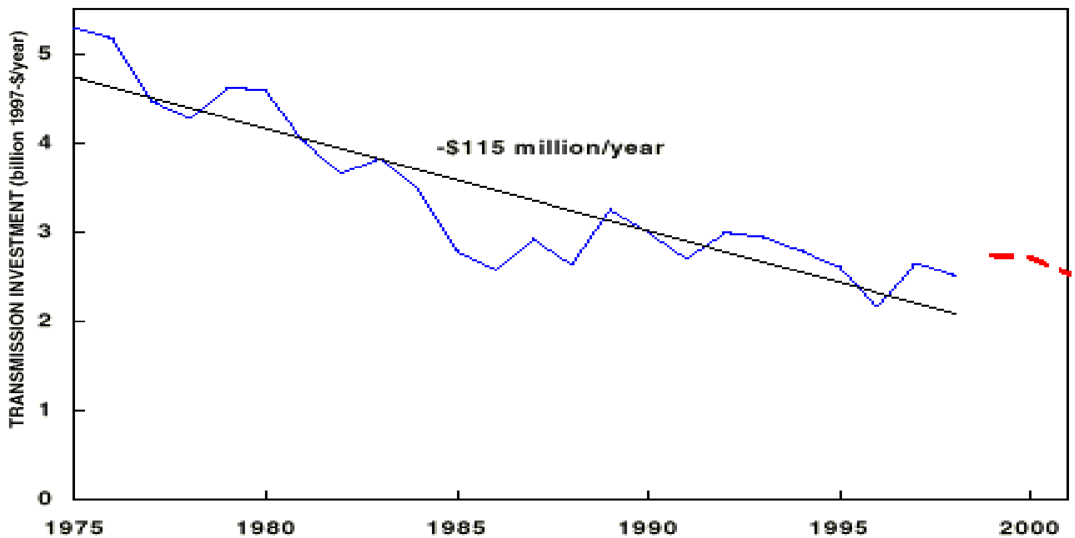
In response to federal deregulation, many states also deregulated access to end-users. This was believed by some states to eliminate the need for need determination due to the fact that market forces would guide additions. Thus, IRPs were also eliminated.

By 2001, a reappraisal of merchant power became a trend, especially in regulated states. It became apparent that the shortages of regulation capacity in most of the country were likely to be replaced at least temporarily with excess capacity. Thus, a question of whether too much was being built became more relevant. Also, the coordination between federal, state and industry entities became more problematic (as federal initiatives grew in scope.)

Additional Comments on Transmission – Power and Natural Gas

As mentioned, the increase in generation capacity in the last few years coincided with a dramatic fall in electric transmission investment. Even though there had been a longer-term trend showing lower investment, the recent fall-off has been most dramatic – especially when compared to the large increase in generation investment by merchants.

Figure 2.5: Historical Decline in Transmission Investment



Source: "Expanding US Transmission Capacity", Eric Hirst for EEI, July 2000

Recently, NERC declared that the nation faces an imminent electricity transmission crisis. Some transmission interfaces have seen significant decreases in available transfer capacity. Transmission costs for new power plants are rising and new entrants increasingly are finding it difficult to access lines. States have increasingly been concerned that the ratepayers will have to pay to solve these problems. This concern has been particularly strong in regulated states. In the view of some, the federal government has unleashed a wave of new plant construction stressing the grid, but left it to state authorities to approve and tend to the grid and collateral effects on ratepayers.

This concern about electric transmission resources derives in part from the difficulty in controlling usage. Power flows cannot be easily controlled or directed. Actions by one company or state affect other companies and states. Analysis of effects is technically difficult. Coordination among power companies on operating procedures retains a strong voluntarily element in spite of the transition to market competition.

Another concern that has emerged relates to natural gas transmission. In California in 2000 and 2001, delivered gas prices rose by a factor of ten or more as demand for gas from power plants increased. Since merchant plants usually purchase gas short-term, they do not necessarily trigger new pipeline additions. Other customers can be affected by increased gas demand if they do not have firm supply. Again, states are increasingly concerned that merchant power developments will have unexpected collateral effects.

Environmental Issues

On the most positive side, siting and environmental concerns about new merchant plants have been decreased by their inherent environmental advantages. New gas plants have no SO_2 emissions, greatly decreased NO_x emissions, especially for combined cycle gas plants, no mercury emissions, and less CO_2 emissions than coal plants. Their space (i.e., site footprint) requirement and water requirements are also less (per MW). Nonetheless, even if concerns are less, there have still been issues about stress on scarce air, water and land resources.

Policy Options

KEY ISSUES FOR STATES

In light of the most recent trends, key issues for state regulators include:

- **Determination of Need** – In light of the growing federal reliance on market forces, is consideration of need still necessary in the case of merchant plants, and if so, what need measures should be used? Whose need should be measured? Does it matter what regional power needs are? If it does, what type of showing is required? Should contracted customers sales be required? If so, for how long, and for what percentage of the plant's output? Do the sales have to be to in-state end users? What about sales to multi-state utilities operating in-state? How can plants finalize contracts before they receive permits? Can contingent contracts be accepted?
- **Appropriateness of Additions** – In light of growing federal reliance on the market forces, should states judge merchant plant appropriateness (e.g., simple versus combined cycle, gas versus coal)? Are qualifications required (e.g., credit worthiness, experience?) What metrics would be used?
- **In-State versus Out-of-State Use** – Do merchant plants need to show benefits to in-state consumers? How much and what kind of benefits should be required?
- **Scarce Resources** – To what extent should there be concern about the use of scarce statewide resources, especially for merchant plants making out-of-state sales? How can determination be made of the extent to which scarcity exists? Could merchant activities help solve problems or at least do no harm? What resources and organizational changes will be needed? At state regulatory institutions, to accommodate merchant plants and other changes in the industry, what should be demanded of applicants?
- **State, Regional and Federal Coordination** – To what extent should states account for developments outside the state? What resources will be needed to participate in such coordination activities? How can redundancy be avoided, and coordination be assumed? What happens to the industry if each state attempts to isolate itself considering the history of reserve sharing, economic trading, joint investments, joint rulemakings, joint research, and emergency coordination?
- **Likely Effects** – How serious are the problems associated with merchant plants and to what extent will federal and regional developments affect the state? Is it feasible to anticipate developments using non-market mechanisms such as studies?

Options for addressing these concerns, especially for regulated states include:

- To centrally inventory transmission, and other resources and approve new plants only in context of doing no harm to the state's limited resources. Utilities would need to coordinate a long-term capacity expansion plan with details on the transmission future of the state.
- More careful and systematic weighing of costs and benefits.
- Tie construction via contracts or via contracts to in-state users. Contracts could provide greater proof of need and ensure all state resources.
- Stopping construction of merchant plants.
- Merchant plants can be approved only if they also contribute to solving problems (e.g., set aside funds for gas or power transmission upgrades).

Countering arguments for greater controls on merchant power plants include:

- Gas plants can be built practically anywhere, and are usually much less polluting than existing plants. Why not allow them to be built in-state where tax benefits and jobs can be obtained?
- Once built, they can provide power in emergencies or in the event the state changes policy.
- Market response to local needs for economy or supplemental power while not perfect will be faster than administrative means. This does not require retail access necessarily.
- Excess capacity and shortages will be temporary and largely self-correcting via market mechanisms.
- Federal improvements will solve some coordination problems and enhance congestion solutions.
- Some competition on wholesale level will be helpful when reviewing utility capacity expansion plans.

CONTENTS OF THE SOUTH CAROLINA UTILITY FACILITY SITING AND ENVIRONMENTAL PROTECTION ACT

The Utility Facility Siting and Environmental Protection Act has changed little since its inception and is consistent with the original design in content. According to the Act, all major utility facilities, defined as all electric generating plants of 75 MW or greater and transmission facilities of 125kV or greater not operated by the South Carolina Public Service Authority, require a certificate issued by the Commission. Although the original design did not specifically mention utility versus non-utility facilities and appears to have been designed for utility facilities, the Act was written in such a way that it is applicable to both utility and merchant facilities in today's market. Note that hydroelectric generating facilities under the FERC jurisdiction are excluded from the Siting Act.

An application to the Commission should include a detailed description of the facility and its location, a summary of any environmental impact studies and a study explaining the need for the facility. A public hearing is held within 60 to 90 days of receipt of the application. The Commission will not grant a certificate for the construction, operation and maintenance unless it determines the following: (a) The basis of the need for the facility (b) The environmental impact of the project (c) that the facility will serve the interests of system economy and reliability (d) assurance that the facility will conform to the relevant State and local laws (e) Public convenience and necessity require the construction of the facility.

The other state agencies involved in the siting process are:

1. South Carolina Department of Health and Environment.
2. South Carolina Department of Natural Resources.
3. South Carolina Department of Archeology and Anthropology.
4. South Carolina Department of Parks, Recreation and Tourism.
5. South Carolina Department of Archives and History.
6. South Carolina Coastal Council.

After the Act's inception, South Carolina continued to see significant new construction activity in the early 1970s, but this activity declined significantly in the late 1970s and new significant capacity additions did not occur again until the early and mid-1980s when significant nuclear capacity came on-line. From the mid-1980s through the 1990s very little capacity was added. The Siting Act saw little activity as few new facilities constructed in the 1990s were subject to the certification requirements. Currently, proposals for expanding capacity have greatly increased and the Siting Act is more heavily utilized for review of new facilities – primarily merchant.

The addition of merchant facilities provides new challenges to the Public Service Commission in reviewing plant applications that were not considered in its original design. When considering new plants under regulated utilities, the Commission did not consider the financial viability of the project or the developer since the utility information was already under the domain of the Commission. Further, although the Act required a statement of capacity need be provided, the requirements and criteria for judging need were not specified. With the limited new construction activity in the state, the need criteria was not a major point of examination. However, with the recent new plant proposals, both utility and merchant, a needs analysis becomes more relevant. Other areas open to examination under the Siting Act include attention to infrastructure requirements, consideration of Federal and regional standards, and impact on State consumers of new facilities.

Recent Plant Applications Under the South Carolina Siting Act

A review of the applications for CECPN (Certificate of Environmental Compatibility and Public Convenience and Necessity) by merchant plants reveals that only a handful of the cases provided detailed discussions on the "Need of the Project". Further, most applications lacked detailed transmission impact studies as well. The applications reviewed were as follows:

1. Broad River Energy Center and Expansion (Calpine Corp./Skygen)
2. Columbia Energy Center (Calpine Corp./Skygen)
3. Greenville Generating (Entergy)
4. Palmetto Energy Center (Calpine Corp.)
5. Cherokee Clean Energy Center (FPL Energy)
6. Anderson County (GenPower Anderson)
7. Greenville County Power (Cogentrix)

Three recent utility additions were also reviewed by the PSC.

1. Mill Creek (Duke Power)
2. Jasper (SCEG)
3. Urquhart (SCEG)

Both the merchant and utility facilities use natural gas or oil. This is consistent with the national trend away from coal and nuclear.

Table 2.1: South Carolina Capacity Expansion by Year

Plant Name	Capacity (MW)	Location of Facility	Status of CECPN Application
Broad River Energy (Calpine)	820	Gaffney	Approved
Columbia Energy Center (Calpine)	500	Carolina Eastman, 10 miles south of Columbia	Approved
Greenville Generating (Entergy)	900	Fork Shoals	Approved
GenPower Anderson	640	Town of Gluck near Anderson	Approved
Greenville County Power (Cogentrix)	810	Fork Shoals	Denied
Cherokee Falls Development Company (FPL Energy)	332	Gaffney	Pending
Palmetto Energy Center (Calpine)	970	Fort Mill	Pending
Jasper Plant (SCEG)	875	Hardeenville	Approved
Urquhart (SCEG)	450	Aiken County	Approved
Mill Creek (Duke)	640	Cherokee County	Approved

BROAD RIVER ENERGY CENTER AND EXPANSION (CALPINE/SKYGEN CORP.)

The first of several applications for merchant plant certification was submitted by Calpine (formerly Skygen) in mid-1999 for the Broad River Energy facility. The facility would have a three-unit simple-cycle combustion turbine totaling 500 MW at a site located in Cherokee county near the town of Gaffney. At the time, the plant was planned to come on-line in June 2001. Approval of this facility was granted within three months of the original application. A later amendment to the original application was filed in early 2000 for an expansion of two additional turbines totaling 320 MW at the site. Approval for the expansion was granted in early 2001.

The units would connect to the existing Duke 230 kV transmission system and connect to the Transco gas pipeline. Both the transmission lines and the gas pipeline cross through the Broad River site allowing for relatively easy interconnections. The application did not include any transmission impact studies related to the facility.

The Broad River Facility was believed to demonstrate a need for capacity through the existence of an already negotiated power purchase agreement (PPA) for the plant output with Carolina Power and Light. This PPA was negotiated in direct response to a Request for Proposal (RFP) issued by CP&L. Under this agreement, CP&L maintained responsibility for all wheeling and transmission arrangements from the site, as well as for all fuel purchases and deliveries. The term of the agreement was to last 15 years from the commercial operation date of the facility.

The capacity need justification for the expansion of the Broad River Energy Center was based on the existence of a term sheet negotiated with CP&L that outlined terms of a definitive power purchase agreement that was similar to the original. The willingness of CP&L to negotiate a long-term PPA was emphasized as a demonstration of the need for capacity. In addition, the application indicated that further justification for an immediate expansion of peaking capacity in VACAR was demonstrated by the high prices of the summers of 1998 and 1999.

Given the long-term PPA agreement, the facility was considered to have limited risk. Likewise, the utility was able to reduce its investment costs since the facility owner would bear this. In this arrangement, CP&L was able to avoid a potential rate increase based on a large capital investment. However, they do bear the full risk associated with fuel and transmission costs.

Currently, the Broad River units are operational.

Columbia Energy Center (Calpine Corp/Skygen Energy LLC)

In late 2000, Skygen Energy LLC submitted a CECPN application for its second merchant plant to be located in South Carolina. The application was to construct a 500 MW combined cycle cogeneration power plant (Columbia Energy Center) to be located on a site leased from Carolina Eastman at its manufacturing plant in Calhoun County and to be commercially operational by June 2003.

The plant will be interconnected to SCEG's transmission system and at the time of the application, Skygen was in negotiations with the South Carolina Pipeline Company for natural gas services. Given the interconnection with SCEG and their concern on the impact to the grid, a detailed engineering analysis including power flow and stability analysis was conducted by SCEG. The study identified three possible interconnection points: (1) a transmission fold-in to SCEG's Wateree-Edenwood 230 kV line; (2) a transmission fold-in to SCEG's Wateree-Edenwood 230 kV line with a new line from the project to the Edenwood sub-station; and, (3) a transmission fold-in to SCEG's Wateree-Edenwood 230 kV line with a new 230 kV line from the Project to the Edenwood substation and a line upgrade from the fold-in point to the Edenwood sub-station. The third option was shown to be the most desirable. Environmental and archeological studies conducted also showed that the proposed transmission lines would not adversely affect wetlands, floodplains, endangered species or historical sites.

As the demonstration of capacity need, the company stated that the long-term Energy Services Agreement (ESA) with Carolina Eastman demonstrated the current and ongoing need for this unit. As per the ESA, Skygen would sell thermal energy to Carolina Eastman for it's manufacturing operations. The Facility would displace generation from the existing on-site coal facility, reducing both costs to Carolina Eastman and pollutant levels. Additional power output would be sold to Carolina Eastman or in the wholesale power market. At the time, Calpine/Skygen was negotiating delivery rights into the SCEG system for wholesale power sales.

Approval for the certification was received in February 2001. The facility is currently under construction.

Greenville Generating (Entergy)

In late 2000, Greenville Generating LLC submitted its application for a CECPN for a merchant plant to be located in South Carolina. The application was to construct a 900 MW combustion turbine facility to be located in Greenville County and to be commercially operational by June 2003. The plant would operate as an Exempt Wholesale Generator and sell power in the wholesale generating market.

The facility will interconnect with the existing Duke 500kV transmission line and with the Transcontinental Gas Pipe Line Company.

As demonstration of capacity need, Entergy presented the testimonies of Steve Stewart, Bradley Williams, Rene Kirchfiled and Joe Marigny. The testimonies stated that average growth in summer peak demand in the SERC region, including South Carolina is expected to be approximately 2.3 percent annually. Further, the forecasts from sources like RDI Outlook, predicted that the SERC region would need an additional 58,000 MW of capacity by 2012. As the demonstration of capacity need, the company would sign a power purchase agreement with a local company. In addition, the company would also sell power to electric cooperatives, local power companies, municipalities and wholesale marketers.

Approval for the certification was received in March 2001. The reasons for the approval were that the company had in its application established the need for the facility, the plant had minimal adverse environmental impacts and that it would serve the interest of system economy and reliability.

PALMETTO ENERGY CENTER (CALPINE CORP.)

Palmetto Energy Center, LLC (a subsidiary of Calpine Corporation) submitted its application for a CECPN in late 2001. The application was to build a 970 MW combined cycle facility to be located in York County, South Carolina. The facility will use combustion turbine technology in a combined-cycle configuration to supply baseload and peaking electricity and will be operational in 2005. The facility will add generating capacity into the Duke transmission system and will be connected to the Transco natural gas pipeline.

As demonstration of need for the project, Calpine Corp. contracted Pace Global Energy Services to forecast market conditions and demand in the VACAR (Virginia and Carolinas) region. According to the study by Pace Global Energy Services, demand is projected to grow by 2 percent a year over the next 20 years. An additional 12,000 MW of generating capacity is needed in VACAR by 2010 and over 40,000 MW by 2025. The energy produced by the facility would represent 7 percent of additional electrical generating capacity needed in VACAR through 2010. An econometric model was used to forecast peak demand and energy levels based on historical relationships between regional demand and historic indicators like population, employment and income between 1989 and 2000. The study established the historical relationships between net energy for load, population, employment and disposable income. The regression analysis showed a strong correlation between electricity demand and the economic indicators.

In order to model the interaction of the facility's generation with the existing transmission system during normal and contingency conditions Duke Energy conducted a detailed engineering analysis. The study consists of a Generation Interconnection Impact Study and a Generation interconnection Facility Study to assess the impact of the proposed generation with Duke's Richmond Line. The Generation Impact Study includes a study of the thermal impact on the transmission system and includes cases performed with and without the other proposed generation and transmission projects. Results indicate that the facility's impact depends on the final determination of the proposed projects in the local area and transmission upgrades are required to accommodate the new generation. Assuming that only the Palmetto Energy Center is developed, the additional generation would have no significant impact. However, if other proposed generation and transmission projects that impact the system in the vicinity of York County are developed, the facility's generation would have the following additional impacts:

1. Additional 525/230 kV transformer capacity would be required at Newport Tie and
2. Additional 525/230 kV transformer capacity would be required at Oconee.

The application is currently pending approval from the Commission.

CHEROKEE CLEAN ENERGY CENTER (FPL ENERGY)

Cherokee Falls Development Company submitted its application to the Commission for a CECPN in late 2001. The application was to build a 332 MW natural gas fired simple cycle peaking power plant in Cherokee County, South Carolina and is expected to be operational by June 2004.The project would involve the construction of a double circuit 100kV transmission line from the generating station switchyard to Duke Energy's Gaffney substation and a connection would also be made with the Transcontinental gas pipeline.

As demonstration of need for the project, the company contracted Pace Global Energy Services, to forecast market conditions and demand in VACAR. According to the study by Pace Global Energy Services, demand is projected to grow by 2 percent a year over the next 20 years. An additional 12,000 MW of generating capacity is needed in VACAR by 2010 and over 40,000 MW by 2025. The energy produced by the facility would represent less than 5 percent of additional electrical generating capacity needed in VACAR through 2010. An econometric model was used to forecast peak demand and energy levels based on historical relationships between regional demand and historic indicators like population, employment and income between 1989 and 2000. The study established the historical relationships between net energy for load, population, employment and disposable income. The regression analysis showed a strong correlation between electricity demand and the economic indicators.

The application for CECPN did not include any detailed transmission impact studies related to the project. The application is currently pending approval from the Commission.

ANDERSON COUNTY (GENPOWER ANDERSON)

In March 2001, GenPower Anderson LLC submitted its application for a CECPN to construct and operate a 640 MW combined cycle facility in Anderson County, South Carolina and scheduled to be operational in June 2003. The facility is a natural gas fired unit and would be connected to the Transcontinental Gas Pipeline Company. The project would involve building a double-circuit 230-kV transmission line to connect the generation station switchyard to Duke Power's Anderson 230-100-44kV Tie Station. The line would be constructed on a route based on a siting study conducted by Duke Engineering Services, Inc.

As demonstration of need for the facility, GenPower Anderson LLC, stated that it was in the process of negotiating a power purchase agreement at the time of its application for a CECPN. The company also contracted Pace Global Energy Services to forecast market conditions and demand in VACAR. According to the study, demand is projected to grow by 2 percent a year over the next 20 years. An additional 14,000 MW of generating capacity is needed in VACAR by 2010 and over 50,000 MW by 2025. The energy produced by the facility would represent 4 percent of additional electrical generating capacity needed in VACAR through 2010. An econometric model was used to forecast peak demand and energy levels based on historical relationships between regional demand and historic indicators like population, employment and income between 1989 and 2000. The study established the historical relationships between net energy for load, population, employment and disposable income. The regression analysis showed a strong correlation between electricity demand and the economic indicators. The Pace study also pointed out that GenPower had selected an appropriate choice for generating technology (i.e., highly efficient power plant using modern combined cycle technology) given the market segment that would be served by the facility.

A transmission line siting report was prepared by Duke Engineering and Service Inc. and by GenPower Anderson, LLC to assess the best route for building the new 230kV transmission line for the project. The siting methodology included environmental, engineering, real-estate, socio-economic and regulatory requirements for the new line. A siting study area was established taking into account the following 2 factors: (1) Location of the plant and (2) Location of the Duke Power Anderson Tie Station. Data from several agencies regarding factors like occupied buildings, hydrography, land use, flood zones, wetlands, land cover and visibility from public roads was entered into the GIS by GenPower Anderson Siting staff. Based on the above data, two alternate route corridors, A (0.6 miles) and B (0.8 miles) were identified. GenPower Anderson, LLC also developed the following route evaluation categories to compare the two alternate routes:

(1) Land Cover Factors
(2) Land Use Factors
(3) Hydrography Factors
(4) Wetland Factors
(5) Flood Zone Factors
(6) Occupied Building Factors
(7) Visibility Factors (Public and Residential)

Within each category, criteria were selected to measure the potential impact of the line on the area and its resources. Route A had the lowest environmental and land-use impacts compared to Route B. Route A would minimize impacts to natural resources and land use over all the factors. After careful consideration, Route A was selected due to the following factors: (1) Environmentally it is marginally better, as it traverses mostly grass and pasture lands, requiring minimal clearing of wooded areas (0.1 acre) compared to Route B that would require clearing 3.7 acres and (2) From a land-use perspective Route A is better. Only one privately-owned tract of land, not owned by Duke Power or GenPower Anderson, LLC is crossed by Route A. This land is owned by the same entity from whom GenPower Anderson acquired the plant site. Route B, on the other hand would cross Owens-Corning's employee recreation area.

Approval for the certification was received in August 2001.

GREENVILLE COUNTY POWER (COGENTRIX)

Greenville County Power, LLC (a subsidiary of Cogentrix Energy, Inc.) submitted its application for a CECPN in September 2001. The application was to build an 810 MW combined cycle unit near Fork Shoals in Greenville County, South Carolina. The facility would burn natural gas as the primary fuel, which would be obtained from the Transcontinental pipeline. The plant is scheduled to be in operation by April 2004. The project would involve building a 525kV single circuit bus line between the generating station and Duke Energy's Harrison Bridge Switching Station across Fork Shoals Road from the generating station.

As demonstration of need for the facility, the application cited load growth in the SERC (specially VACAR – Virginia and Carolinas) region. Since 1996, electric loads in SERC have grown at 2.8% annually, with the VACAR sub-region growing the highest, at 3.2 percent. According to the June 2001, "Regional Electric Supply and Demand Projections" (EIA Form 411) report filed by utilities in the SERC region, there is an additional need for over 38,000 MW of new capacity (including planned unit retirements and firm purchases and sales) in the SERC region by 2010. Of this capacity over 17,000 MW of capacity is needed in VACAR. Committed resource plans by electric utilities in VACAR are projected to satisfy only 30 percent of the total need by 2010, resulting in about 12,000 MW of future capacity need for which resources have not been committed. Even if non-utility generation projects are included, approximately 2,000

MW of future capacity needs remain uncommitted for by 2004 (9,800 MW by 2010) in VACAR. According to the company, the project would help satisfy part of this future need.

A Generation Interconnection Impact Study was conducted by Duke to identify the network modifications required to accommodate the plant. Duke Electric Transmission also prepared a Generator Facility Study describing the switchyard modifications and associated support facilities to be provided by Duke. However, details of the above studies were not included in the Greenville County Power's CECPN application.

The Commission denied certification for this facility on the grounds that the air quality studies were not complete and it lacked any studies gauging the plant's effect and impact of removal of wastewater from the Reedy River.

MILL CREEK (DUKE POWER)

In March 2001, Duke Power submitted its application for a CECPN, to build a 640 MW combustion turbine plant (Mill Creek) in Cherokee County, South Carolina. The project is expected to be operational in June 2003.

As demonstration for need of the project, Duke filed its Annual 2000 Plan with the Commission. The plan includes a 15-year load forecast, near-term power purchase contracts, existing generation, demand-side management resources and peaking and intermediate generation technologies. The plan identifies the need for an additional 2,200 MW of new resources to meet customers' energy needs by summer 2004. In Duke Power Company's 1999 Annual Plan filing, annual average growth in summer peak demand is projected at 1.9 percent and winter peak demand at 1.5 percent. Energy growth is projected to grow at 2.1 percent. Duke's Annual Plan incorporates a 17 percent planning reserve margin.

The project would involve construction of a double circuit 230kV transmission line to connect the plant to Duke's existing Ripp's Switching Station. Ripp Switching Station is an existing major bussing point for Duke Electric Transmission System from which eight 230-kV lines emanate. The switching station is connected to Catawba Nuclear Station, Riverbend Steam Station, Shelby Tie Station and Riverview Switching Station. In order to accommodate the facility, Ripp Switching Station will need to be expanded to accommodate the new transmission lines coming from the site. The expansion would involve enlarging the current substation footprint, some modifications and relocations of existing lines as well as rebuilding 10 miles of the existing Ripp to Shelby transmission line. The plant is currently under construction.

URQUHART PLANT (SCEG)

In early 2000, SCEG (South Carolina Electric and Gas) submitted its application for a CECPN, to build a 450 MW combined cycle facility and associated transmission lines to be located in Aiken County, South Carolina. The facility will include two turbine generators rated at approximately 150 MW each. In addition, two of the existing steam generators with a capacity of 75 MW each will be repowered. The project will include the construction of two additional 230 kV transmission lines of 6.3 miles in length from the Urquhart Station to connect to the existing Graniteville to Savannah River Site.

As demonstration of need, SCEG cited that its total territorial energy needs are projected to increase at an annual rate of 2.4 percent from 2000 to 2004. Its peak demand is forecasted to increase by 896 MW during the next decade. According to SCEG, without the additional capacity of the proposed plant, SCEG will be unable to meet the increasing need for power.

The application for CECPN did not include a detailed transmission impact analysis. The facility is currently under construction.

JASPER COUNTY PLANT (SCEG)

In late 2001, SCEG submitted its application for a CECPN, to build an 875 MW combined cycle facility to be located in Jasper County, South Carolina. The plant will be composed of three combustion-turbine generators, three (heat recovery steam generators) HRSGs and one steam turbine-generator.

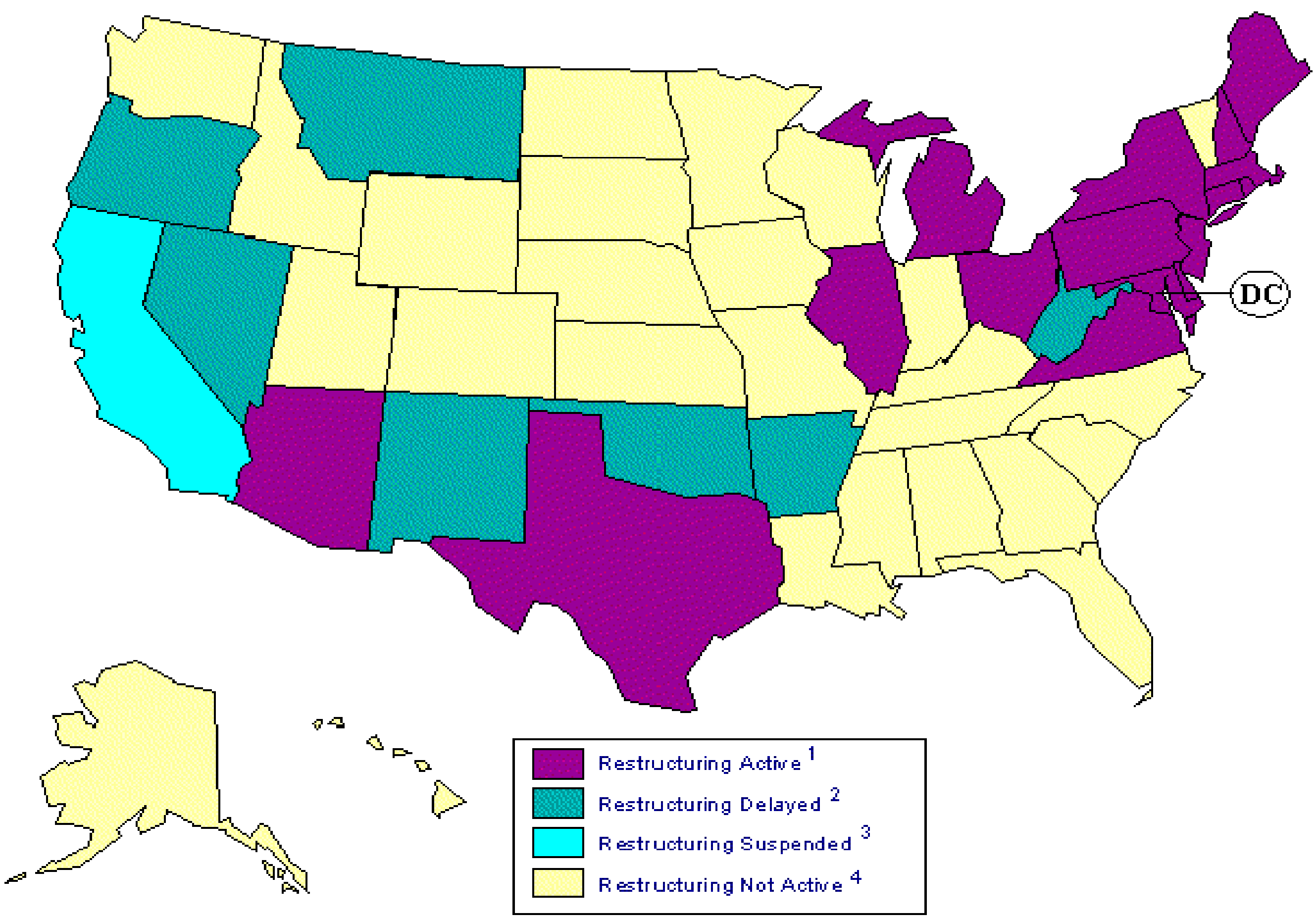
As demonstration of need, SCEG cited that it's total generating capacity is 4,588 MW including power available from long-term purchase agreements with other utilities and non-utility generators. SCEG's peak demand is forecasted to increase by 857 MW during the next decade. According to SCEG, without the additional capacity of the proposed plant, SCEG will be unable to meet the increasing need for power and meet system reliability. The application for CECPN did not include a detailed transmission impact analysis.

CHAPTER THREE: PLANT SITING ACTIVITY IN DEREGULATED VERSUS REGULATED STATES

This chapter is organized in three sections, the first discusses development in deregulated states while the second section addresses development in still regulated states. The third section addresses FERC's proposal for standardization of generator interconnection agreements and procedures. Although FERC's proposal does not directly address siting of generators, it is important to consider given the emphasis on common treatment and standardization requirements in review of infrastructure development across regulating agencies.

For purposes of this discussion, deregulated states are those shown below with a status of "active". Given the initial deregulation in California, we also include California as if it were in the active deregulation category. The Northeast region along with Texas is more involved in restructuring activity compared to the rest of the nation and will be discussed first. The southeast region is much less involved as most states have decided to delay or reject any kind of deregulation activity and will be the focus of the second section of this chapter.

Figure 3.1: Status of Deregulation Activity in the U.S.



Siting and Permitting of New Power Plants: Comparison with Deregulated States

Deregulated States

State regulatory activity related to siting, determination of need and environmental appropriateness has been heavily affected by the extent of statewide deregulation. Some deregulated states have been anxious to encourage the construction of merchant power plants and have explicitly eliminated consideration of need as criteria for a permit. Examples of such states include California. These states have also discontinued IRPs and competitive bidding for long term supply. Some have also adopted bidding for supplier of last resort.

Table 3.1: New Facility Certification Criteria for Select Deregulated States

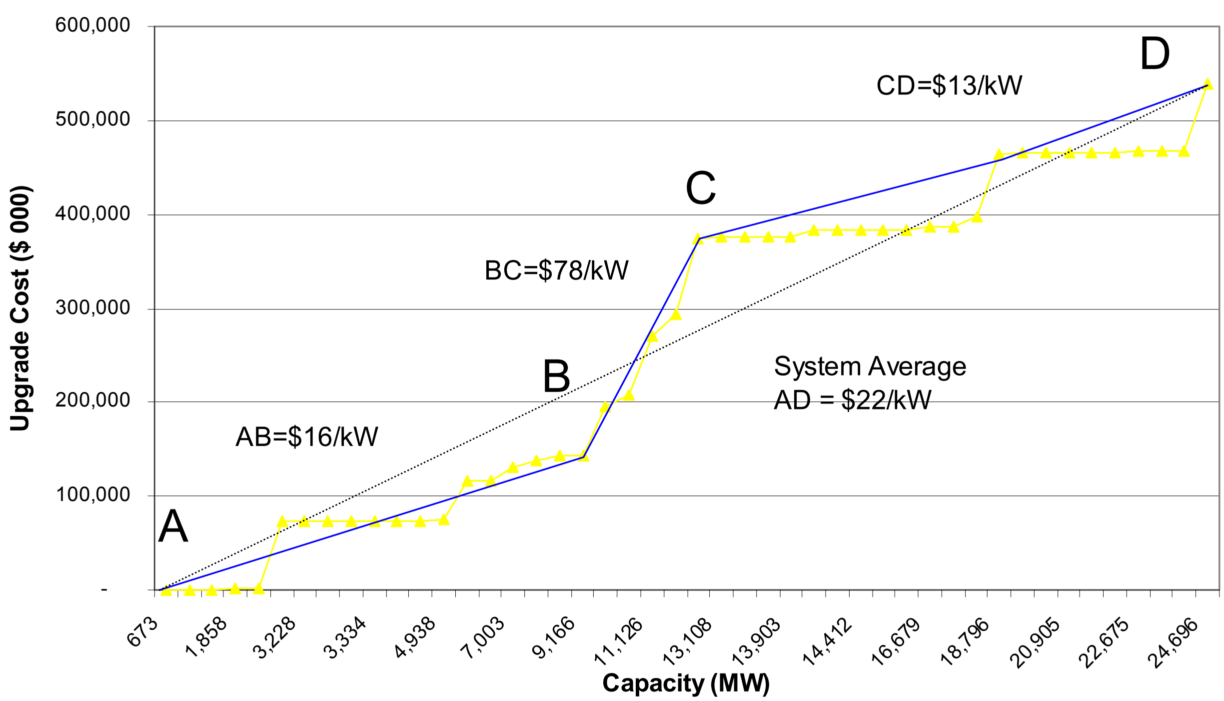
State	New Regulated Utilities (RU) Facility Certification	New Merchant Facilities (MP)	Environmental Permitting Requirements	Transmission Impact Review
Virginia	State Corporation Commission.	State Corporation Commission.	State/Local Air and Water	N/A
Delaware	No certification required	No certification required	State/Local Air and Water	Conducted by PJM ISO
Maryland	Public Service Commission.	Public Service Commission.	State/Local Air and Water	Conducted by PJM ISO
New Jersey	No certification required	No certification required	State/Local Air and Water	Conducted by PJM ISO
Pennsylvania	No certification required	No certification required	State/Local Air and Water	Conducted by PJM ISO
Connecticut	Connecticut Siting Council.	Connecticut Siting Council.	State/Local Air and Water	Conducted by NEPOOL ISO
Maine	No certification required	No certification required	State/Local Air and Water	Conducted by NEPOOL ISO
Massachusetts [1]	Energy Facilities Siting Board.	Energy Facilities Siting Board.	State/Local Air and Water	Conducted by NEPOOL ISO
New Hampshire[2]	New Hampshire Energy Facility Site Evaluation Committee	New Hampshire Energy Facility Site Evaluation Committee	State/Local Air and Water	Conducted by NEPOOL ISO
Vermont	Public Service Board.	Public Service Board.	State/Local Air and Water	Conducted by NEPOOL ISO
Texas	No certification required	No certification required	State/Local Air and Water	Conducted by ERCOT ISO
California[3]	California Energy Commission	California Energy Commission	State/Local Air and Water	Conducted by the Transmission Owners and reviewed by the CA ISO

1. Only facilities greater than 100 MW subject to review.
2 Only facilities greater than 30 MW subject to review.
3 The California Energy Commission has the statutory authority to site and license thermal power plants 50 MW or larger.

In some parts of the country, multi-state entities already exist and are heavily involved in new power plant additions as they affect the grid. Examples of the longest running include NEPOOL and PJM. Their focus is on the effects of interconnection. The goal is to prevent clear direct impacts on existing operations. If some are found, entrants are required to pay for upgrades. The extent to which new entrants can be made to pay for system upgrades is subject to FERC control and has been the subject of disputes, especially in New England.

The interconnection focus does not address general effects on congestion which is handled via market mechanisms such as nodal pricing and firm transmission rights. For example, available firm transmission rights are sold at auction. The interconnection focus also does not address the issue that upgrade costs are affected by the order of interconnection. As shown, PJM hook-up costs have been rising significantly over time.

Figure 3.2: PJM -ISO Cumulative Transmission Upgrade Costs ($ 000)
All Projects Firm and Withdrawn



We highlight developments in four areas in which deregulation has occurred: PJM, NEPOOL, California, and Texas.

PJM

Developers in Pennsylvania, New Jersey, Delaware and Maryland wanting to interconnect to the PJM grid must complete the PJM Regional Transmission Expansion Planning Process and undergo detailed transmission feasibility and system impact studies that are done by the PJM ISO. All projects received by the PJM ISO are assigned a queue position based on the date of submission and involve the following procedures:

1. Interconnection Request
2. Feasibility Study Agreements and Deposit
3. Feasibility Study Executed

4. System Impact Study Agreements and Deposit
5. System Impact Study Executed
6. Facilities Study Agreement and Deposit
7. Facilities Study Executed
8. Interconnection Service Agreement

A summary of the important procedures involved with obtaining an Interconnection Agreement in the PJM ISO is given below:

FEASIBILITY STUDY:

1. Assesses the practicality and costs of incorporating the unit into PJM. The analysis uses load flow analysis of the more probable contingencies and short circuit studies and does not include stability.
2. The study focuses on determining preliminary estimates of type, scope, cost and lead-time for construction of facilities required to interconnect the project.
3. After reviewing results of the Feasibility Study, the applicant decides whether or not to proceed with the System Impact Study.
4. If applicant decides to proceed, a System Impact Study Agreement is submitted along with $50,000 deposit. Proof of initial application for air permits is required.

SYSTEM IMPACT STUDY:

1. Involves a comprehensive analysis of the impact of adding the new generation to the Interconnection and its deliverability to PJM load.
2. Identification of the system constraints relating to the project and the attachment facilities, local upgrades and network upgrades required.
3. A study of the relationships between the new generator, other planned new generators in the queues and the Interconnection as a whole.
4. An analysis of existing firm and non-firm transmission service requests.
5. After reviewing the study results, the applicant must decide whether or not to continue with the project.

FACILITIES STUDY:

1. The Facilities Study Agreement provides the estimated cost responsibility and estimated completion date for the study.
2. Defines milestone dates that the project must meet to retain its assigned priority.

Upon completion of the Facilities Study, PJM will provide a good faith estimate of the cost to be charged for attachment facilities, local upgrades and network upgrades required to accommodate the project and estimated time required for construction of the facility and upgrades.

In order to proceed with the Interconnection Service Agreement, the applicant must show within 60 days of receipt of the Facilities Study that it has met certain milestones. The facility must show that it has entered fuel delivery and water agreements as necessary. It must have obtained the necessary local, county and state site permits; and signed a memorandum of understanding for the acquisition of major equipment.

A developer may engage an independent consultant to conduct transmission impact studies; however, the ISO will conduct its own studies before granting the Interconnection Service Agreement. Most of the power flow studies and analyses are done by the PJM ISO staff, however independent contractors are also used in some cases. Sometimes local transmission owners are consulted since they best understand the voltage system and the generator's impact on the transmission system. Requests for the interconnection of new generation resources of less than 10 MW may be processed through expedited procedures. Large projects do not have an expedited process and studies are conducted based only on the queue basis.

NEPOOL

Vermont, New Hampshire, Massachusetts and Connecticut require new power plants to obtain certification from the state agencies. Maine does not require power plants to be approved by the Public Utility Commission, but all plants need to obtain the necessary environmental and local permits. However, like PJM any new generation or an upgrade to an existing unit must be reviewed in terms of how it will impact the regional transmission system and involves detailed system impact studies done by the NEPOOL ISO.

The main procedures involved in obtaining an Interconnection Agreement are similar to PJMs and are described below.

APPLICATION:

1. A request for the study of a new interconnection must be made in an application accompanied by the application fee.
2. The application must include all information required on the application form, including a notarized verification and description of the form of site control and a detailed map indicating the site of the new facility.

SYSTEM IMPACT STUDY (SIS) AGREEMENT:

1 Following receipt of a Completed Application for an SIS, the ISO will, within 30 days of the receipt of the Completed Application, tender an SIS Agreement.
2. To maintain a Completed Application, the applicant should execute the SIS Agreement and return it to the ISO within 15 days of receipt of the agreement.
3. The applicant must submit within 30 days all data and other information required for the SIS Agreement, which significantly impacts the projected completion of the study.
4. The applicant can elect not to proceed with the SIS Agreement, at which point the application is deemed withdrawn.

SYSTEM IMPACT STUDY PROCEDURES:

1. The SIS is a rigorous assessment to ensure that the new generation added to the system would not adversely impact its reliability or operating characteristics.
2. The study involves: (A) Determining the impact of the proposed generation on the local transmission provider's system (B) identifying the specific modifications needed to incorporate the new generation, such as transmission lines, terminal equipment, protection and control systems (C) providing cost estimates for transmission upgrades and additions to the system.
3. A draft report is provided to the applicant. The applicant has 15 days to provide its comments, failing which the report will be issued without the applicant's comments.
4. Once the SIS is completed, the developer can decide how to proceed.

FACILITIES STUDY PROCEDURES:

1. If no transmission upgrades are required, a Facilities Study is not needed.

2. If transmission system modifications are needed, the ISO will tender to the applicant a Facilities Study Agreement (FSA) within 30 days of submission of the final SIS report
3. The applicant shall execute the FSA within 15 days of receipt of the agreement. If it elects not to execute the FSA, its application shall be deemed withdrawn.
4. Upon receipt of an executed FSA, the ISO and the supporting transmission providers will use due diligence to cause the study to be completed within a period specified in the FSA. The completed FSA shall include all related Interim Facilities Studies, which may have been performed.

INTERCONNECTION AGREEMENT:

1. If the SIS indicates that no transmission upgrades are needed, the applicant and the interconnecting Transmission Provider shall establish appropriate interconnection agreements and the applicant shall provide required security, within 90 days following issuance of a final SIS report.
2. If upgrades are required, the applicant and the interconnecting Transmission Provider shall establish appropriate interconnection agreements and the applicant shall provide required security, within 90 days following issuance of a final FSA report.
3. Failure to establish such interconnection agreements and provide required security will result in the application being deemed terminated and withdrawn.

The System Impact Studies (SIS) are usually assigned to an independent contractor to perform. The completed SIS is forwarded to ISO-NE for review and approval. Generators 5 MW or less are exempted from complying with interconnection rules and procedures.

Texas

In Texas any generating entity requesting transmission interconnection must submit an application to the ERCOT ISO. Applicable ERCOT and National Electric Reliability Council (NERC) standards, guides and/or procedures for accurate system representation and modeling will be followed and the process includes the following steps:

1. ISO Review of Request and Acknowledgement
2. ISO Performs Steady State Security Study
3. The Generating Entity Agrees to Proceed, Deposit & Site Control Received
4. Develop Study Scope
5. Steady State & Transfer Analysis Study
6. Dynamics Analysis
7. System Protection Analysis
8. Facilities Study
9. Study Report Review

California

The California Energy Commission (CEC) is the primary authority responsible for siting and licensing all thermal plants that are 50 MW or larger. All plants need an AFC (Application for Certification) from the Commission prior to construction, including impact studies. Prior to deregulation, all applicants submitted as part of the AFC a statement of need showing that the proposed project conformed with the most recently adopted Electricity Report that also contained an economic analysis for new resource additions. The Electricity Report and Integrated Assessment of Need (IAN) provided the means of implementing statewide planning of new generation facilities. However, deregulation SB 110 enacted in September 1999, waived the “determination of need” requirement for power plants. The rationale being that before restructuring, it was necessary for the Commission to engage in planning and approve only those plants which were needed, because ratepayers paid for the facilities. Since power plants are now at risk to cover their own investments, this determination of need is no longer appropriate. According to SB 100, "Before the California electricity industry was restructured, the regulated cost recovery framework for power plants justified requiring the commission to determine the need for new generation, and site only power plants for which need was established. Now that power plant owners are at risk to recover their investments, it is no longer appropriate to make this determination." Currently, the three objectives of SB 110 are: "insure electricity reliability, improve environmental performance of the current electricity industry and reduce consumer costs". These three objectives comprise the statewide interests which supplant "integrated assessment if need."

The CEC has 12 months to complete its analysis, though there is an expedited process wherein applications are granted within 6 months. This process is applicable to all power plants that pose no significant environmental impacts. In order to connect with the grid, the generating facilities need the approval of the California ISO. The transmission owners conduct the transmission impact studies. The ISO reviews these studies and may conduct sensitivity analysis of the impact studies. All costs associated with the interconnection to the grid are borne by the generator.

In terms of environmental permitting the policies of the deregulated states are similar to those of the regulated states, in that all developers require the relevant air and water quality permits from the environmental agencies.

REGULATED STATES

Of course many states like South Carolina have not deregulated and have no plans to deregulate. The rank ordering of states still regulated is shown below. South Carolina is the tenth largest by size.

Table 3.2: Currently Regulated States Sorted by 2001 Generation

State	Industry		Utility		Non Utility	
	2000	1999	2000	1999	2000	1999
Florida	190,936	186,928	169,890	166,914	21,046	20,014
Indiana	127,970	121,594	119,724	114,183	8,247	7,411
Alabama	124,554	120,865	118,040	113,909	6,514	6,957
Georgia	123,067	117,681	116,180	110,537	6,887	7,144
North Carolina	122,114	117,588	114,435	109,882	7,679	7,705
Washington	108,811	117,135	96,223	112,072	12,588	5,064
Tennessee	95,918	93,419	--	--	--	--
West Virginia	92,783	94,781	89,708	91,678	3,076	3,103
Kentucky	92,630	93,108	81,351	81,658	11,279	11,450
South Carolina	92,614	90,330	90,424	87,347	2,190	2,982
Louisiana	89,938	90,096	57,597	64,837	32,341	25,259
Missouri	76,626	73,827	76,286	73,505	340	322
Wisconsin	59,230	58,500	55,668	54,704	3,562	3,796
Oklahoma	55,441	55,016	51,403	50,279	4,038	4,737
Minnesota	51,429	48,607	46,618	44,154	4,811	4,453
Oregon	51,415	56,708	46,060	51,698	5,355	5,010
Wyoming	45,257	43,632	44,586	42,951	672	681
Kansas	44,834	42,070	44,766	42,003	67	67
Arkansas	43,975	46,622	41,489	44,131	2,486	2,491
Colorado	43,661	39,530	40,109	36,167	3,552	3,363
Iowa	41,519	38,842	39,634	37,032	1,885	1,810
Mississippi	37,516	34,915	33,896	32,212	3,620	2,703
Utah	36,590	36,812	35,828	36,071	763	741
Nevada	35,639	32,800	29,342	26,486	6,297	6,315
New Mexico	33,994	32,581	32,857	31,654	1,137	927
North Dakota	31,284	31,421	31,123	31,260	161	161
Nebraska	29,122	30,057	29,046	29,981	76	76
Idaho	11,967	14,404	10,114	12,456	1,853	1,948
Hawaii	10,652	10,503	6,536	6,452	4,117	4,050
South Dakota	9,697	10,557	9,697	10,557	--	--
Vermont	6,282	5,709	5,307	4,735	975	975
Alaska	6,140	5,812	4,938	4,609	1,202	1,202
Total Regulated States	2,023,605	1,992,450	1,768,875	1,756,114	158,816	142,917

Similar to South Carolina, other southern states like Mississippi, Louisiana, Kentucky and Tennessee have recently been concerned about the proliferation of merchant facilities in their states and have proposed studies to determine the impact of merchant plants or are considering similar studies. Kentucky and Tennessee have issued moratoriums on new plant applications. Kentucky lifted its moratorium in April 2002. However, it passed a legislation creating a seven-member board to review merchant plant development issues. Any company wanting to build a merchant project in the state will require the board's approval. Tennessee issued a similar moratorium on new power plants in August 2001 that was lifted in March 2002. Currently only 4 private power plants will be approved in the state in the next two years giving regulators time to assess their economic and environmental impacts.

South Carolina is currently concerned regarding an overbuild situation should all new plants that are in the pipeline be approved, especially merchant plants. Some other states in the southern region also share the same concern and are considering studies to review the impact of merchant plant builds (e.g., Louisiana and Mississippi). Although Louisiana does not have any formal studies or reports underway it is concerned about the impact of all power plants, i.e., merchant plants and utilities on groundwater usage. Mississippi also has no on-going study but is considering reviewing the impact of merchant plants in the state. In Georgia, the Governor last year formed a task force to collect and analyze data and develop a comprehensive statewide strategy for permitting new plants. Others like Kentucky and Tennessee (moratorium was in effect from August 2001 to March 2002) issued moratoriums on new plant applications given the proliferation of applications received in the recent past.

It is evident from Table 3.3 that most of the states in the southern region, wherein restructuring activity is not active, have concerns regarding siting merchant plants.

Table 3.3: Merchant Plant Siting Activity Status for Select States

State	Merchant Siting Review Status	Moratorium in Effect
South Carolina	Ongoing study	No
Mississippi	Considering a review of the merchant plants and impact; no formal study done to date.	No
Kentucky	Legislation (SB 257) was passed in April 2002 creating a seven member siting board, to determine where merchant plants should be located. Any merchant project will require the board's approval.	Initially moratorium on new plants was in effect from June 2001 to June 2002. However, this was lifted in April 2002, when SB 257 was enacted.
Tennessee	An executive order created in March 2002, establishing a two-year demonstration project to manage only 4 merchant power plants. The pilot project will allow Tennessee to fully assess the economic and environmental impact o f merchant plants. The executive order requires merchant power plants to receive a certificate from the Department of Economic and Community Development prior to proceeding with permitting and transmission agreements.	Moratorium was in effect from August 2001 to March 2002
Louisiana	Concern regarding the impact of power plants (Merchant and utilities) on the groundwater usage. No formal study/report done.	No
Georgia	In May 2001, the Environmental Protection Division of the Georgia Department of Natural Resources notified applications that NO_x and water concerns prompted the agency to slow down permitting. Governor formed a task force to collect and analyze data and develop a comprehensive statewide strategy for permitting new plants.	No
Indiana	No concern regarding merchant plant activity; ongoing study regarding the impact of merchant plants on gas transmission	No
Florida	No study or concern regarding merchant plant activity. Siting currently extremely limited.	No
Alabama	No study or concern regarding merchant plant activity	No

Table 3.3: Merchant Plant Siting Activity Status for Select States (continued)

North Carolina	No study or concern regarding merchant plant activity	No
Arkansas	No study or concern regarding merchant plant activity	No
Virginia	No concern regarding merchant plant activity. Effective July 1, 2002, the Virginia State Corporation Commission cannot impose any environmental regulations over and above those issued by the Department of Environmental Quality. Thus, the environmental permits granted by the DEQ are final.	No

The issuance of recent moratoriums on current new power plants, especially merchant plants, in Kentucky and Tennessee indicate the difficulty in siting a power plant. Florida and Mississippi require both regulated utilities and merchant plants to be approved by the Public Utilities Commissions and the time taken from application to obtaining a certificate is quite lengthy compared to other southern states (one to two years).

States considered moderate in siting requirements include Alabama and Georgia. In terms of their permitting process, only regulated utilities require certification from the State authorities. Merchant plants do not require any approval except for the relevant state and local environmental permits. Some other states such as North Carolina, South Carolina, Maryland and Virginia require both regulated utilities and merchant plants receive approval from the Public Utilities Commission.

Siting and Permitting of New Power Plants: Comparison with Regulated States

Most states have certain siting regulations for new power plants, some more stringent than others. A review of the Southern states reveals that most of them fall into one of the following two categories: (1) all power plant developers require certification/approval from the state agencies (i.e., regulated utilities and merchant plants) or (2) only regulated utilities require certification and merchant plants don't fall within the state jurisdiction. A common requirement for all states in both the above categories is that all proposed facilities need to be in compliance with all relevant environmental regulations.

South Carolina is among those states that require all power plants to obtain a Certificate of Environmental Compatibility and Public Convenience and Need (CECPN) prior to construction. Some of the other states in this category are North Carolina, Mississippi, Indiana, Florida and Virginia. South Carolina and the above mentioned states are similar in their policies to a certain extent in that the petitioner must establish that the proposed facility fills some demand for public convenience and necessity. For example, according to the South Carolina Siting Act "the Commission may not grant a certificate for the construction, operation and maintenance of a major utility facility, either as proposed or as modified by the Commission, unless it shall find and determine the basis of the need for the facility."

States that fall in the second category (i.e., those in which only regulated utilities require certification) are Louisiana, Arkansas and Alabama. Initially Kentucky was also in the above category. However, the recent proliferation of new power plant applications led the Governor to issue a moratorium on all new plants effective through July 2002. The moratorium was lifted in April 2002 and Kentucky passed a legislation (S.B. 257) creating a seven member siting board to determine where merchant plants should be located. Henceforth, any regulated or unregulated company building a merchant project will need approval by the board. Regulated utilities will report to the state Public Service Commission. Municipal utilities will be exempt from the legislation unless they plan to build merchant plants. Thus, Kentucky, like Florida, will be one of the most difficult states to site new merchant plants.

Table 3.4: New Facility Certification Criteria for Select Regulated States

STATE	New Regulated Utilities (RU) Facility Certification	New Merchant Facilities (MP)	Environmental Permitting Requirements	Transmission Impact Review
South Carolina	Public Service Commission	Public Service Commission	State/Local Air and Water	Transmission Impact Studies required for new transmission line facilities greater than 125 kV or more; new electric generation facilities may or may not submit Transmission Impact Studies.
Alabama	Public Service Commission	No certification required	State/Local Air and Water	N/A
Arkansas	Public Service Commission	No certification required	State/Local Air and Water	Transmission Impact Studies required for new transmission line facilities that are: (1) more than 170kV and more than 1 mile in length or (2) more than 100kV and more than 10 miles in length; new electric generation facilities involving upgrades do not require to submit Transmission Impact Studies.
Florida[1]	Public Service Commission	Public Service Commission	State/Local Air and Water	N/A
Georgia	Public Service Commission	No certification required	State/Local Air and Water	N/A
Kentucky	Public Service Commission;	Seven member siting board established in April 2002, no prior review required	State/Local Air and Water	N/A
Louisiana	Public Service Commission	No certification required	State/Local Air and Water	N/A
Mississippi	Public Service Commission	Public Service Commission	State/Local Air and Water	No Transmission Impact Review required.
North Carolina	Utility Commission	Utility Commission	State/Local Air and Water	N/A

1. The governor and cabinet have final authority over certification and siting of major generation and transmission plant additions. The PSC determines whether such additions are needed.

Most of the regulated states do not have any well-defined criteria for certification of plants and they involve, at best, random technical assessments of the project. Most of the states require projects to demonstrate "need for the facility" as an important criterion of the approval process. However a study of some actual orders granted by states reveals that in most cases "the need for the facility" was not adequately defined. Most cases (actual orders in North Carolina, Virginia and Mississippi) lacked a detailed analysis or studies demonstrating the "need" for the proposed facility. Documents like reliability studies by NERC and SERC, EIA forms (e.g., Form 411) and company IRPs (Integrated Resource Plans) were cited and relied upon to show demand growth in the relevant regions and thus the need for additional capacity. Only a couple of cases in South Carolina cited detailed econometric analyses that were conducted by independent consultants showing "need for capacity" (e.g., Palmetto Energy Center, Cherokee Clean Energy

Center and Anderson County that contracted independent consultants like Pace Global Energy Services to forecast market conditions in the SERC region). All the regulated states however, have stringent regulations for assessing the environmental impacts of the new facilities, (whether it is a regulated utility or merchant plant) and require the plants to obtain the necessary state and local air/ water quality permits prior to plant construction.

DEREGULATED VERSUS REGULATED STATES

Although in some of the deregulated states like Pennsylvania, New Jersey and Delaware and Texas the Public Utility Commissions do not have jurisdiction over siting and approval of plants, any new facility wanting to interconnect to the PJM or ERCOT grid must obtain an Interconnection Service Agreement. The ISOs conduct detailed system impact studies before granting approval for a new generator to interconnect to the grid. Similar procedures are used for new generating facilities in the New England region as well.

One perspective is that irrespective of whether a merchant plant is located in a regulated or deregulated state, there is a sense in which it would undergo a more detailed analysis in the certification process when compared to a regulated plant. This is because securing project financing for merchant plants is more difficult and involves certain risks. The main risks associated with merchant plants are market risk, project risk (includes construction, technology and operating risks) and structural risks (includes legal/regulatory and financing risks). Some states accept the market as a guide; other do not. The attitude is tied back to the decision to deregulate in the first place.

FERC'S PROPOSAL FOR STANDARDIZATION OF GENERATOR INTERCONNECTION AGREEMENTS AND PROCEDURES

Although the FERC proposal for standardization does not directly address the siting of new power plants, it is focused on the interconnection agreement of new facilities. FERC's proposal recognizes that interconnection is a vital component of open access transmission service, and believes that in order to provide the right market incentives to transmission providers and generators that standard interconnection agreements and procedures are essential.

In April 2002, FERC issued a NOPR (Notice of Proposed Rulemaking) and has recommended standard IA (Interconnection Agreement) and IP (Interconnection Procedures) that will be made part of existing and future OATTs. The FERC's IP recommendations are similar to those of the PJM and NEPOOL ISO. Further, the Midwest ISO's (MISO) procedures for new generators to obtain Interconnection Agreements have been structured using FERC's IP as a model. A summary the Standard Interconnection Procedures is provided below:

Interconnection Request:

1. Interconnection Request including a refundable deposit of $10,000 that will be used toward the cost of an Interconnection Feasibility Study.
2. Within 10 days after receipt of a valid Interconnection Request, an Initial Scoping Meeting between the Transmission Provider (TP) and generator will be set up.

Queue Position:

1. The TP shall assign a queue position based on the date and time of receipt of the valid Interconnection request that will be used to determine the order of performing the studies and cost responsibility.

Interconnection Feasibility Study:

1. Will involve preliminary evaluation of the feasibility of the proposed generation interconnection to the Transmission system and will consist of power flow and short circuit analysis.
2. The feasibility study will consider the base case and include all those generating facilities that, on the date the Interconnection Feasibility Study is commenced are directly interconnected to the transmission system, those interconnected to affected systems and having a potential impact on the interconnection request, those having a pending higher queued Interconnection Request to interconnect to the transmission system and those generators having no queue position but an executed Interconnection and Operating Agreement.
3. The generator is responsible for all costs associated with the study and any re-studies that may be required.

Interconnection System Impact Study (SIS):

1. The generator will execute the Interconnection System Impact Study Agreement and deliver the same to the TP along with a $50,000 deposit.
2. The system impact study will evaluate the impact of the proposed interconnection on the reliability of the transmission system and will consist of a short circuit analysis, stability analysis and power flow analysis.
3. The SIS will state the assumptions of the study, results of the analyses, potential impediments to providing the requested interconnection service, a preliminary estimate of the cost and time necessary to correct the problems identified in those analyses.
4. The SIS will provide a list of facilities required due to the Interconnection Request and a good faith estimate of the cost and timing to construct the facilities.
5. The TP shall coordinate the SIS with the any system that is affected by the Interconnection Request.

Interconnection Facilities Study:

1. The Interconnection Facilities Study shall include cost estimates of the equipment, engineering, procurement and construction work needed to implement the conclusions of the SIS.
2. The Facilities Study shall identify the electrical switching configuration of the connection equipment including the transformer, switchgear, meters and other station equipment, and the nature and cost of any Transmission Provider Interconnection Facilities and Network Upgrades required for the interconnection.

Optional Study:

1. The generator may request the Transmission Provider to perform some operational studies.
2. The optional study will consist of a sensitivity analysis based on assumptions specified by the generator and will identify the costs required to provide interconnection service based on results of the optional study.

3. Optional studies will be performed solely for informational purposes and the Transmission Provider shall use existing studies to the extent practicable in conducting these studies.

Interconnection and Operating Agreement:

1. Draft Interconnection and Operating Agreement will be tendered by the Transmission Provider to the generator along with the draft Interconnection Facilities Study report.
2. Along with the final Interconnection and Operating Agreement, the generator must show that one or more of the following milestones has been achieved: (a) supply/transportation contract for fuel to the facility (b) Execution of contract for supply of cooling water to the facility (c) execution of contract for the engineering and procurement of major equipment or construction of the facility (d) execution of a contract for the sale of electric energy or capacity from the facility (e) application for an air, water or land use permit (f) posting of $250,000 non-refundable additional security, which shall be applied toward future construction costs.

Construction of Transmission Provider Interconnection Facilities and Network Upgrades:

1. The Transmission Provider and generator shall negotiate a schedule for constructing the needed facilities and upgrades.
2. In general, the service dates of the generators will determine the sequence of construction of network upgrades. However a generator may request an expedited completion of the network upgrades if those are the responsibility of another entity and would otherwise not be completed in time to support the generator's in-service date. The generator is responsible for all costs associated with the upgrades.

Small Generator Interconnection Requests:

1. Small generators defined as units not more than 20 MW, will have the deposit requirement for the Interconnection Studies waived. However they would be responsible for all costs of processing the Interconnection Request and studies, unless these are waived.
2. Expedited procedures will be used for small generators' Interconnection Requests and Studies but they will be placed in the same queue as other generators.

FERC's Standardized Interconnection Procedures are not in effect currently. However, for those RTO's and states that currently do not have any interconnection procedures in place, the procedures provide a model.

This proposal represents an industry trend toward common rulemaking, however, it also begs the question on what should be the correct authority to make decisions regarding development in an RTO or state. The FERC proposal tends to apply directly to RTOs. However, organizations like the National Organization of Regulatory Utility Commissioners (NARUC), recommend that states play a more active role. In order to prevent any states' authority from being compromised, NARUC supports an active involvement from states in both generation and transmission siting. NARUC has supported the formation of voluntary regional outfits to address issues such as siting of transmission, identifying regional bulk power market needs, and planning for construction of new interstate facilities. These volunteer agencies would also serve to establish mechanisms to resolve disputes where individual states involved have conflicting views. Only in the absence of such regional involvement would NARUC suggest the involvement of FERC.

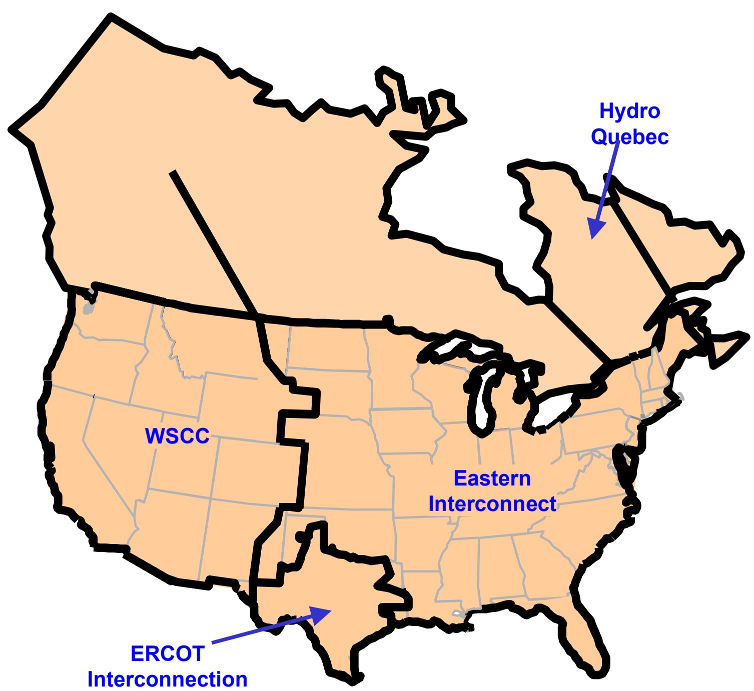
CHAPTER FOUR: SOUTH CAROLINA ELECTRIC INDUSTRY STATUS

ORGANIZATIONAL OVERVIEW

There are several entities relevant to understanding South Carolina's position in the industry. They include:

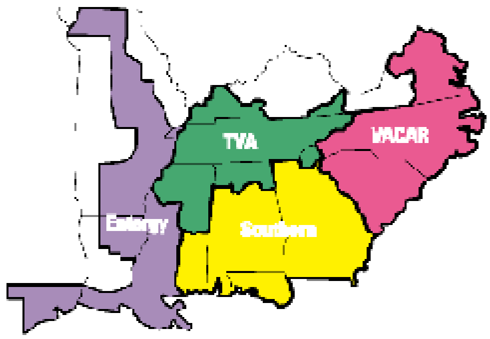
- **Eastern Interconnect** – The synchronous grid in which South Carolina is located. This is one of three grids in the continental U.S. and is the largest grid in the world.

Figure 4.1: Interconnected Grids in the U.S. and Canada



- **Southeastern Electric Reliability Council (SERC)** – One of North American Reliability Council (NERC) regional councils. NERC is a voluntary organization nearly four decades old. As mentioned, South Carolina is located within the Southeastern Electric Reliability Council. In addition to South Carolina, SERC includes all or parts of 12 states in the Southeastern and South Central U.S.: Alabama, Arkansas, Florida, Georgia, Kentucky, Louisiana, Mississippi, Missouri, North Carolina, Tennessee, Texas, and Virginia making it among the largest regional reliability councils in the US.

Figure 4.2: Southeast Regional Reliability Areas



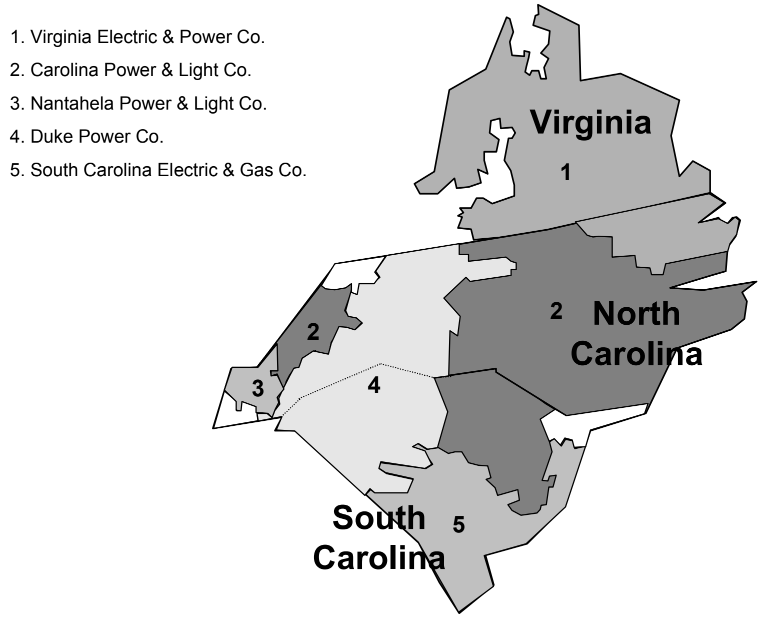
Source: www.serc1.org

SERC is divided into four sub regions: Entergy sub region; Southern sub region (Georgia, Alabama, and part of Mississippi and the panhandle of Florida); Tennessee Valley Authority (TVA) sub region; and the VACAR sub region (Virginia and the Carolinas). Historically, SERC has provided a high degree of autonomy to each of its sub-regions and to utilities within these sub-regions. Three of the four sub-regions reflect the boundaries of large utilities: Southern Company ("Southern"), Entergy, and the Tennessee Valley Authority ("TVA"). Only the South Carolina sub-region of VACAR has a diverse utility composition: Virginia Power ("VEPCo"), Duke, Carolina Power and Light ("CP&L"), and South Carolina Electric and Gas ("SCEG") spanning Virginia and the Carolinas.

SERC, in general, but especially VACAR, TVA, and Southern, relies heavily on coal and nuclear generation. The use of coal is related to the Appalachian coal fields that extend down to the center of this area. Indeed, of a handful of utility coal plant additions in the last decade, two were located in VACAR in the state of South Carolina.

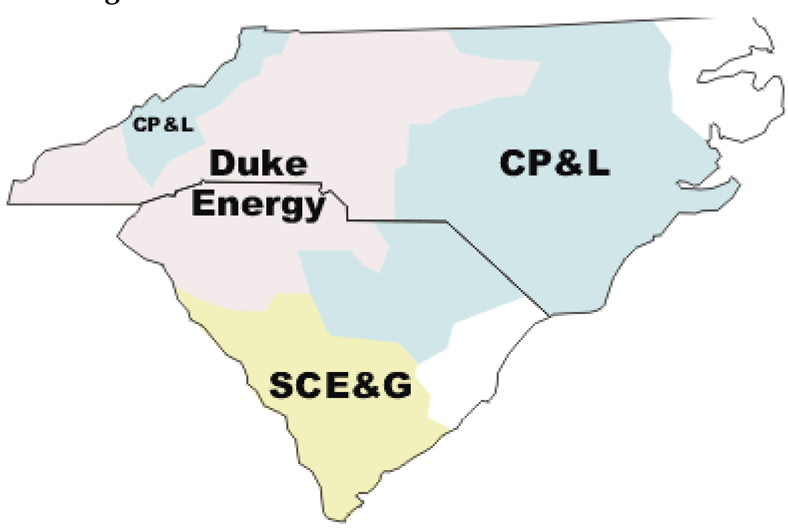
- **VACAR** – VACAR is comprised of several large utility systems and a number of cooperatives and municipal entities. It is not currently a centrally dispatched or "tight" power pool. In fact, it has a history of no tight inter-utility power pooling. Major investor-owned utilities in VACAR include Virginia Electric & Power Co. (Virginia Power and North Carolina Power) (VEPCo), Carolina Power & Light Co. (CPL) which recently merged with Florida Progress (parent company of Florida Power Corporation), Duke Power Co. and Duke operating subsidiary Nantahela Power & Light, and South Carolina Electric & Gas Co. (SCEG). Cooperatives or municipalities include Santee Cooper, South Carolina Public Service Authority, North Carolina Electric Membership Cooperative (NCEMC), City of Fayetteville and Old Dominion Electric Cooperative. The service territories for these utilities and other smaller utilities are illustrated below.

Figure 4.3: Major Participants in VACAR



- **Grid South** – A proposed RTO spanning North and South Carolina. This regional organization was originally proposed in July 2000 and filed with FERC in October 2000. Since the original filing, much uncertainty regarding the FERC RTO regulation has prevailed. Given this uncertainty, the member utilities of Grid South in February of this year withdrew their applications with their respective state commissions to transfer control of their transmission assets to Grid South. It is unclear whether the utilities will attempt to go forward with Grid South.

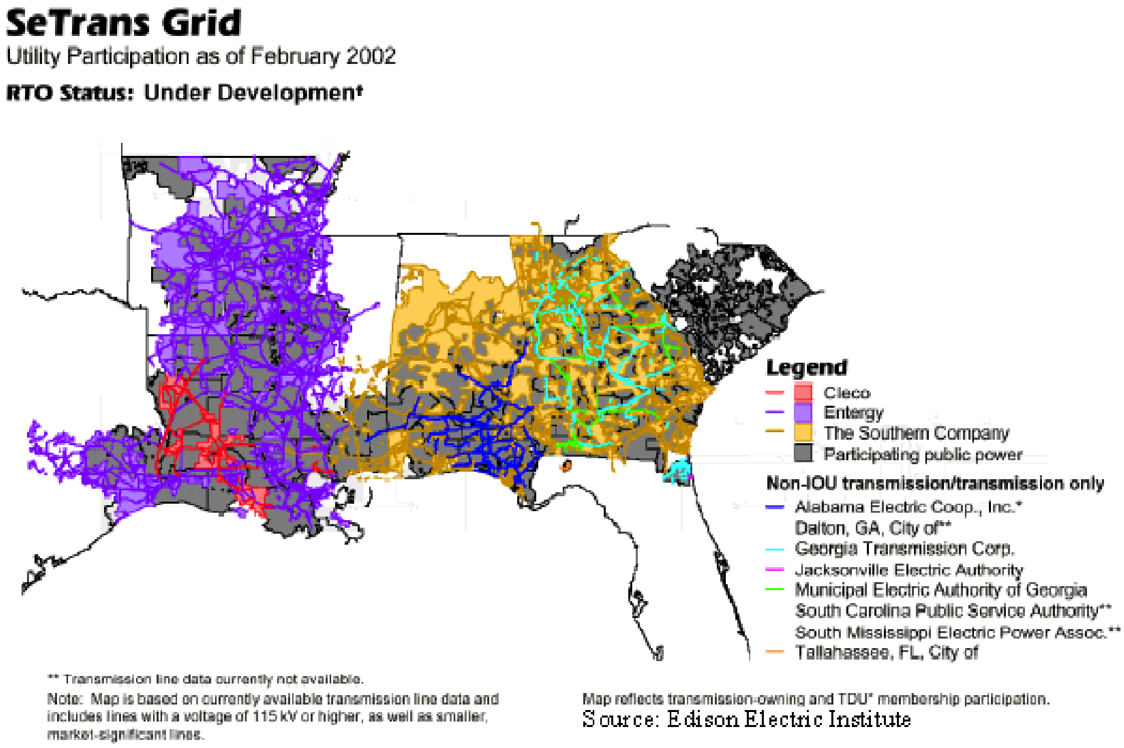
Figure 4.4: Grid South Transco Initial Members



- **SeTrans** - A new organization for transmission in the southeast U.S. currently proposed by nine southeast utilities. The SeTrans RTO development process is being proposed by the following companies: CLECO, Dalton Utilities, Entergy Services, Inc., Georgia Transmission Corporation, JEA, MEAG Power, Sam

Rayburn G&T, South Carolina Public Service Authority, South Mississippi Electric Power Association, Southern Company and City of Tallahassee, Florida

Figure 4.5: SETrans Grid



- **South Mega RTO** – A concept promoted by FERC.
- **Multi-state Companies** – Multi-state electric utility companies traditionally operating in South Carolina include Duke and Carolina Power and Light (Progress Energy).

South Carolina

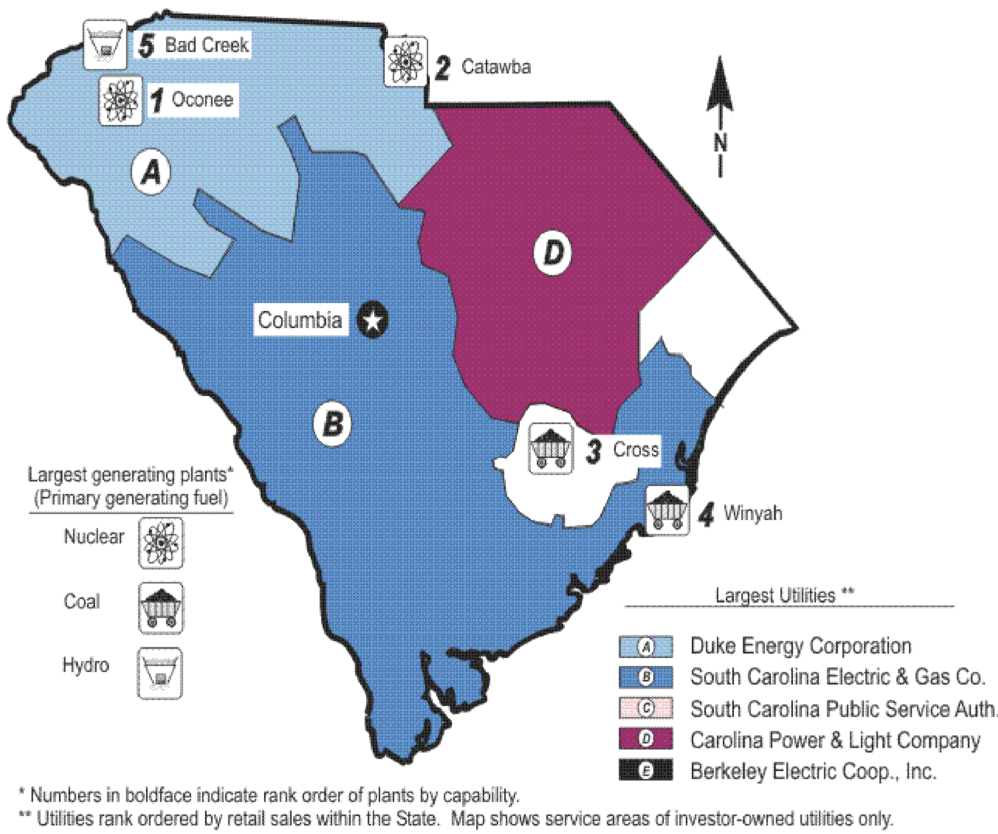
South Carolina represents the most diverse state in VACAR in terms of ownership and sales distribution. Both North Carolina and Virginia have a high degree of concentration in the top market participants share of the total market – Virginia is dominated by one large player and North Carolina is dominated by two large players. South Carolina has four relatively large players and several smaller active participants.

There are four investor owned utilities regulated by the Public Service Commission in South Carolina.

- Carolina Power and Light
- Duke Power
- Lockhart
- South Carolina Electric and Gas

Combined, these utilities represent nearly 1 million residential customers and about 65 percent of total utility retail sales in the state.

Figure 4.6: South Carolina Electricity Network Highlights

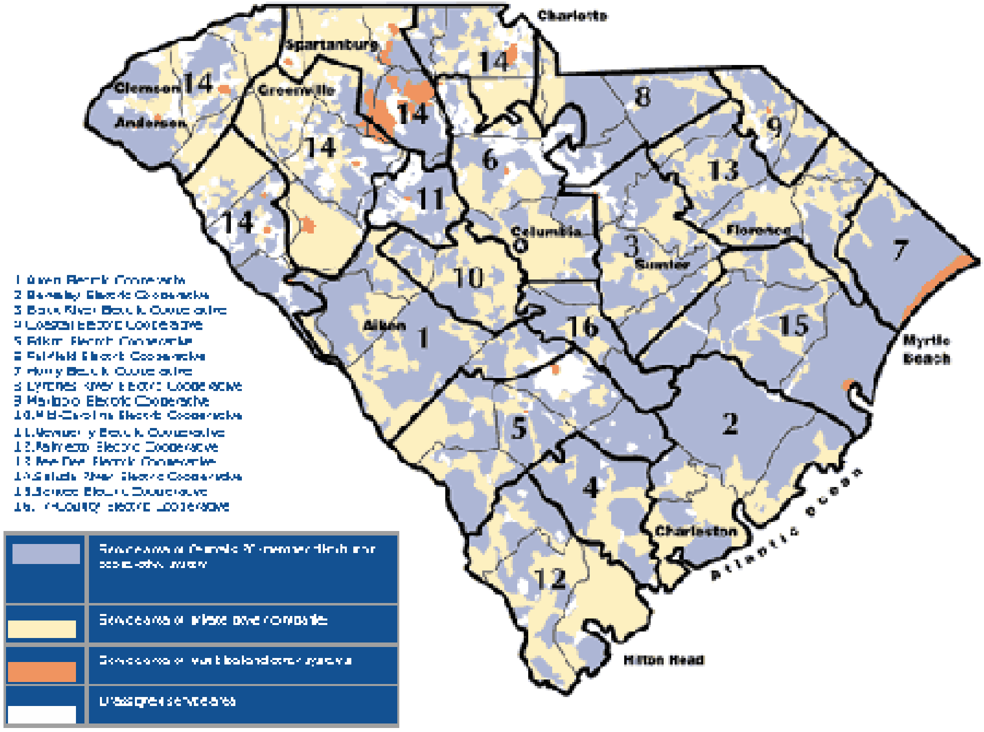


Source: Energy Information Administration, www.eia.doe.gov

There are further 20 cooperatives in the state providing service to rural areas in 46 counties not served by the investor owned utilities. Santee Cooper, the South Carolina Public Service Authority, is the primary source for power distributed to the state's cooperatives. Santee Cooper also provides direct service to residential and commercial customers in Berkeley, Georgetown and Horry counties in Eastern South Carolina. In addition to cooperative sales, Santee Cooper supplies power to 32 large industrial facilities, two cities and one military base.

In addition to Santee Cooper, Central Electric Power Cooperative (wholesale power generation and transmission cooperative), New Horizon Electric Cooperative (wholesale power transmission cooperative), Saluda River Electric Cooperative (wholesale power generation cooperative), and Cooperative Electric Energy Utility Supply CEE-US (materials supply cooperative) provide generation and transmission services to the state cooperative agencies.

Figure 4.7: South Carolina Service Territories



Source: www.ecsc.org/cepc/map.htm

As shown above, the service areas for these cooperative agencies covers a broad expanse within South Carolina and is intertwined within the utility networks. Santee Cooper does not fall under Public Service Commission jurisdiction, but rather is governed by a statewide board of directors appointed by the governor. Nor are other cooperative agencies regulated by the Public Service Commission.

Electric Generation Capacity Mix

In comparing South Carolina to other states in the Southeast, the capacity mix reflects a much greater dependence on nuclear generating facilities. In terms of percent of total capacity, South Carolina has nearly double nuclear capacity of the next closest state. In contrast to most states in the Southeast, South Carolina does not rely as heavily on coal resources in its capacity mix, although there is still a significant amount of coal reliance. South Carolina’s coal capacity represents 30 percent of its total capacity while it’s neighbors of North Carolina, Tennessee and Georgia have 56, 44, and 43 percent of total capacity in coal resources respectively.

Table 4.1: Expected 2003 Capacity Mix in Southern States
(% of total capacity by state)

Capacity Type	AL	FL	GA	KY	NC	SC	TN	VA
Nuclear	14.8	7.9	12.6	--	17.2	32.1	16.3	16.1
Coal	45.6	26.3	43.3	73.5	55.7	29.2	43.9	29.1
Oil/Gas	27.8	63.7	32.8	22.3	20.6	21.3	20.8	38.1
Hydro	11.4	0.15	11.8	4.2	5.8	17.4	18.1	15.2
Other	0.4	2.0	0.1	--	0.7	--	0.9	1.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Source: ICF's Integrated Planning Model.

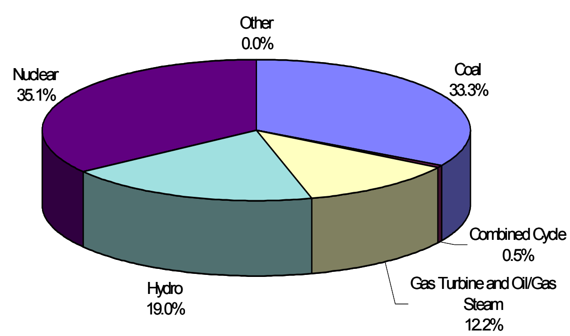
The remaining capacity in South Carolina is a mixture of hydro and peaking turbine facilities. Only two conventional oil/gas steam units operate in South Carolina, totaling just 100 MW at the Jefferies Plant. The remainder of the oil and gas-fired capacity has historically been at large number of small peaking turbine facilities.

South Carolina and VACAR have a significant amount of baseload capacity reflecting several factors:

- **Coal** – The region obtains its coal primarily from Central Appalachia. The cost of delivered coal to the region makes existing coal units very competitive with new baseload combined cycles that use natural gas.
- **Nuclear** – The general VACAR region has approximately 14.5 GW of nuclear capacity, the last of which came online in the mid-1980s. The nuclear units in the region have had high historical capacity factors.
- **Natural Gas** – Almost no natural gas is produced in VACAR. It also has one of the highest delivered gas costs in the Eastern Interconnect. Thus, many peaking units that could use gas often use oil.

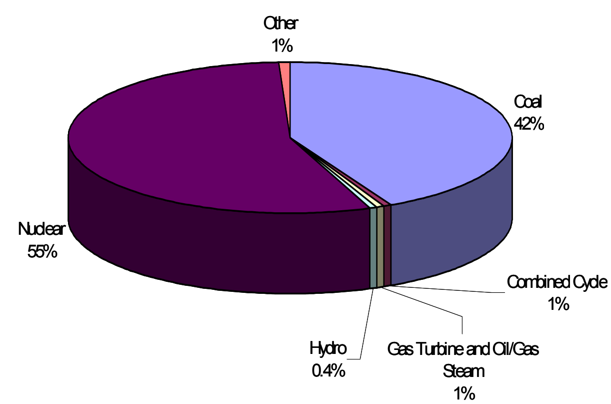
Figure 4.8: South Carolina 2000 Capacity and Generation Mix

Total Capacity = 18.4 GW



Source: NERC ES&D 2001

Total Generation = 92,324 GWh



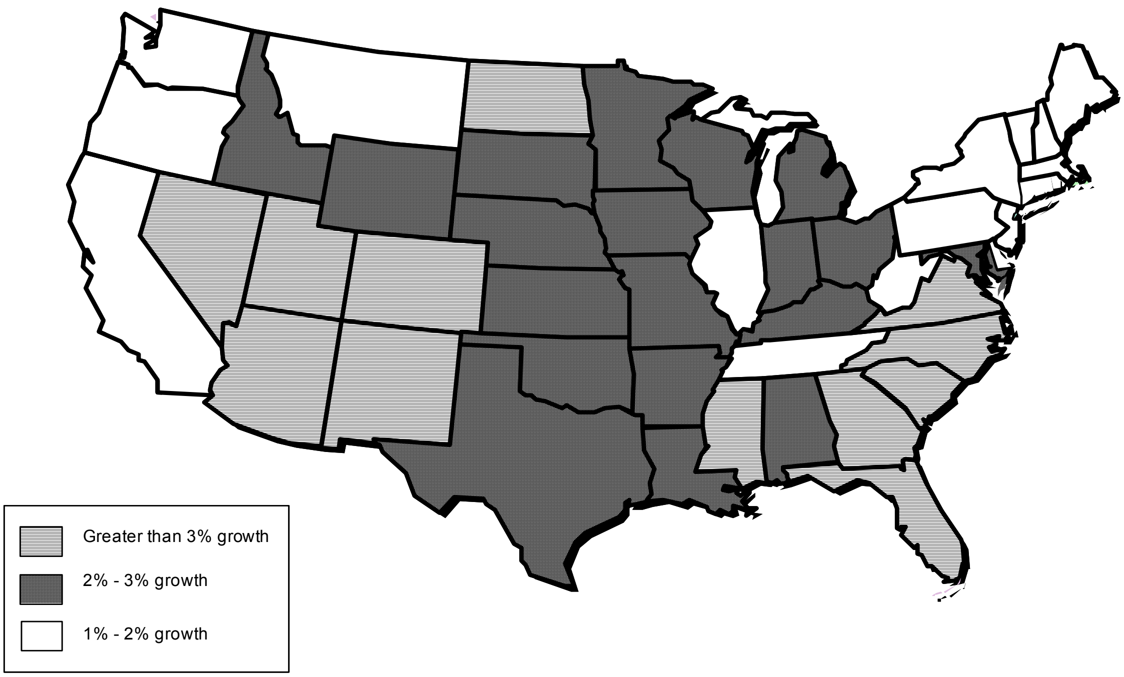
Source: EIA Form 759 and 900 c

Source: NERC ES&D 2001.

The domination of nuclear and coal resources in South Carolina is even more striking when examining generation within the state. Of total output produced by the South Carolina capacity, nuclear and coal generation combined to form 97 percent. Hydroelectric resources had very little generation, as did the existing oil- or gas-fired capacity.

ENERGY SALES (CONSUMPTION) AND GENERATION

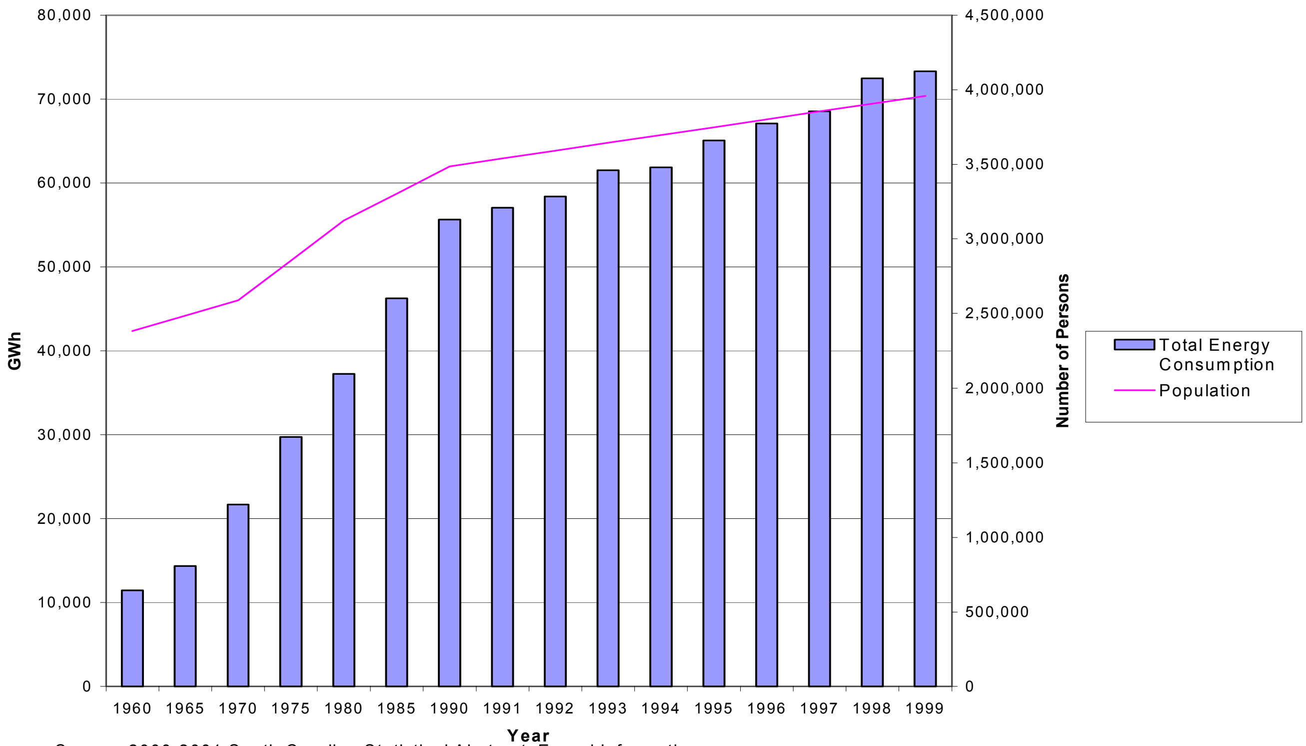
Figure 4.9: Total Electric Energy Consumption Growth – South Carolina Relative Status Compared to Southeastern States



Along with the majority of the Southeastern states, South Carolina has experienced stronger growth in energy requirements than the average US (between 2% to 3%). Strong continued growth expectations exist for South Carolina and the SERC sub-regions. Capacity requirements are expected to continue to grow at strong rates within South Carolina and the larger SERC area.

SUPPLY AND DEMAND BALANCE

Figure 4.10: South Carolina Electricity Use versus Population Growth

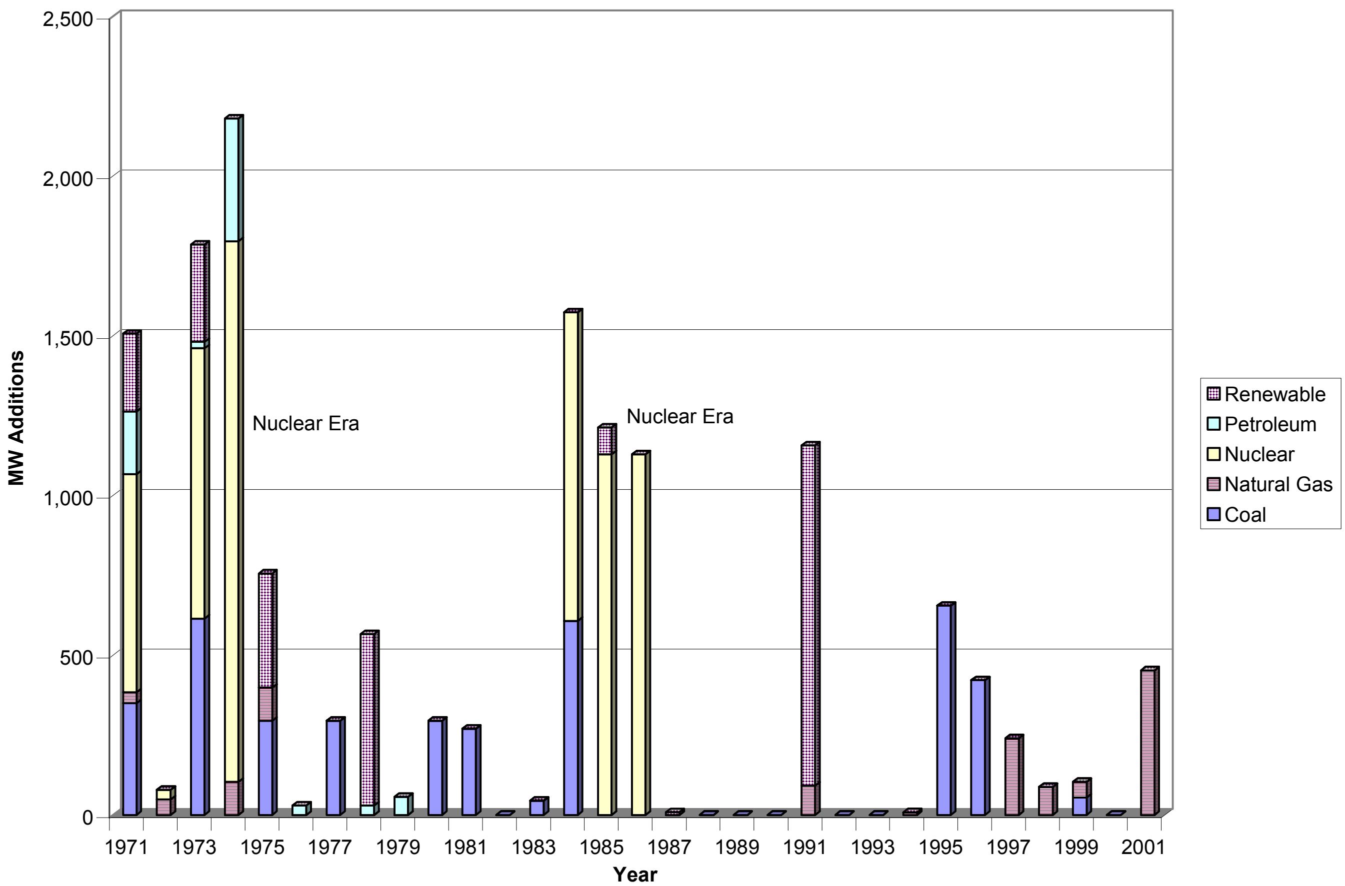


Source: 2000-2001 South Carolina Statistical Abstract; Energi Information

South Carolina is summer peaking with an estimated peak demand of around 17 GW. South Carolina has seen very fast historical growth in electricity requirements. Growth in use of electricity in South Carolina has outstripped growth in the state population. By 1999, consumption per customer was roughly 4 times what it was in 1960. Energy Consumption in the State grew at an average annual rate of 5 percent per year versus only a 1 percent population growth rate. Note that this increase in consumption has been seen in all market sectors with commercial and residential consumers outpacing industrial consumers although industrial customers continue to have the highest total consumption. Although consumption growth has slowed over the last decade, it is still high at above 3 percent annually and continues to outpace population growth.

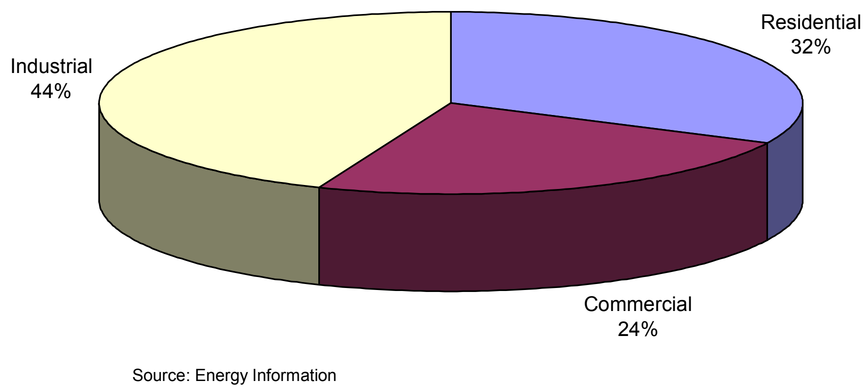
Capacity additions in South Carolina since the early 1980s including large addition of nuclear units has been limited. At the time of the Siting Act in the early 1970s, there were large additions of capacity that were needed to meet growing demand requirements. By 1975, South Carolina had become a net energy consumer, importing energy from other states. Through the late 1970s, capacity additions continued, balancing out the states energy consumption from out of state sources. However, continued expansion in the 1980s again resulted in South Carolina becoming a net energy exporter and remaining so in today's market.

Figure 4.11: Historical South Carolina Annual Capacity Additions by Size and Type



In peak periods, South Carolina is expected to require roughly 17 GW of firm supply capability. Given current build expectations, sufficient supply resources are expected to be available for in-state supply even at peak load.

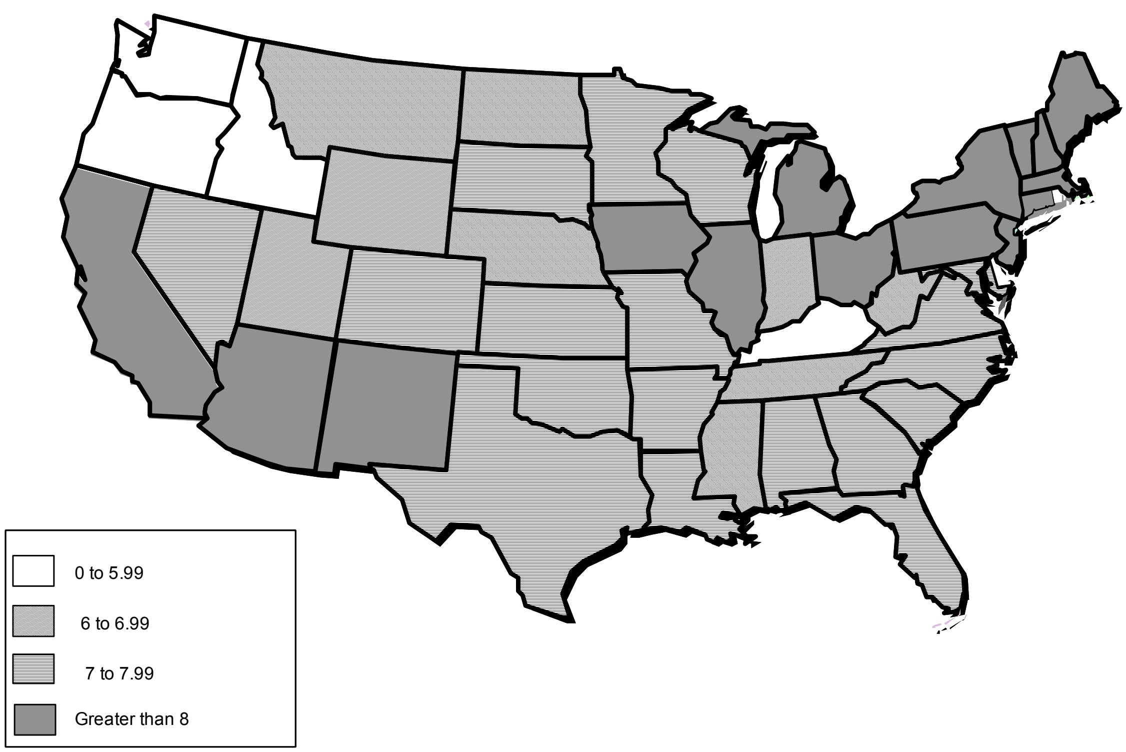
Figure 4.12: Energy Consumption In South Carolina by Type, 1999



Industrial consumption has historically represented the largest share of electricity consumption in the state. This large industrial base has contributed to generally low overall rates in the state given the cost of servicing industrial customers is generally below that of residential and commercial consumers. Further discussion on retail rates is provided below.

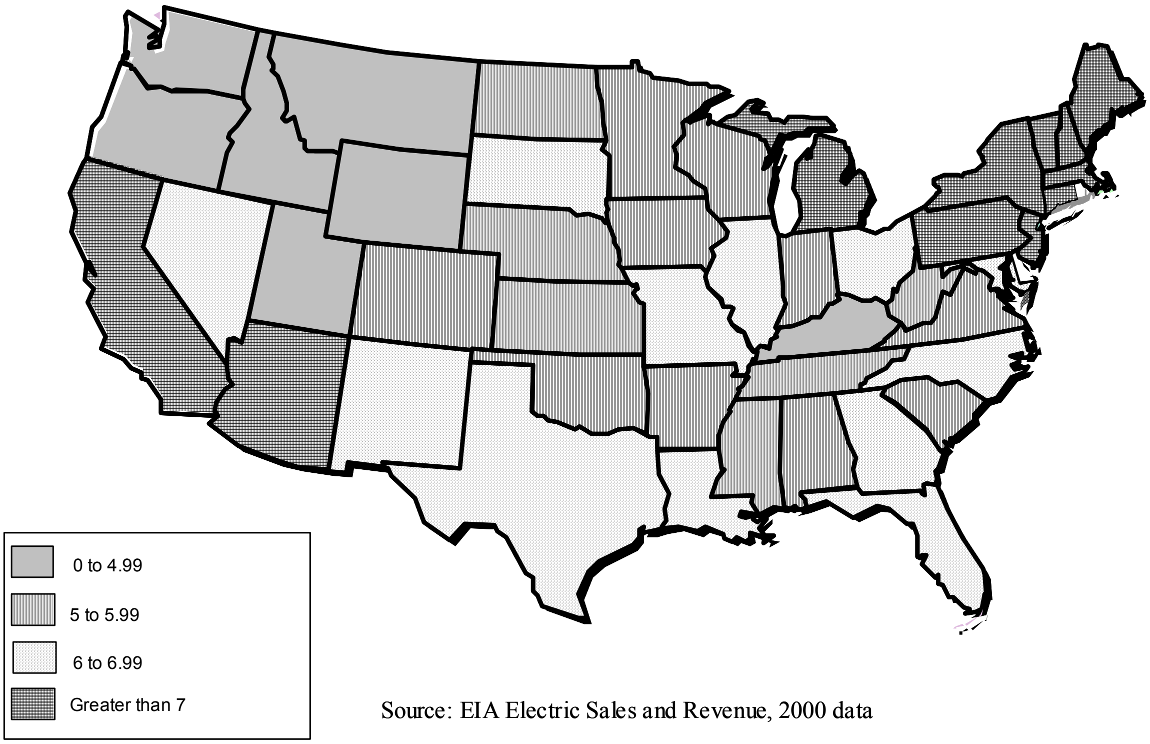
RETAIL RATES

Figure 4.13: Average Residential Revenue per Kilowatt-hour in the United States ($/kWh)



The Northeast states and California have among the highest residential and total average revenue per kWh while states in the Northwest have the lowest. The Southern and Midwestern regions have relatively moderate rates.

Figure 4.14: Average Revenue per Kilowatt-hour in the United States, All Sectors ($/kWh)



Source: EIA Electric Sales and Revenue, 2000 data

Retail rates in South Carolina are considerably lower when considering industrial and commercial sector rates as well as residential. Relative to other Southeast regions, South Carolina has a larger than average share of the market in the industrial sector – North Carolina, Florida, Georgia; Alabama and Tennessee combined have a 25 percent Industrial share versus the 44 percent Industrial share in South Carolina. Rates in the industrial market have a special rate design resulting in lower rates than the residential sector given that they have predictable or consistent large volume usage and can connect directly to the transmission grid and avoid distribution costs.

CHAPTER FIVE: SOUTH CAROLINA NATURAL GAS INDUSTRY STATUS

This Chapter will focus on issues related to natural gas markets in South Carolina. Specifically, the Chapter will focus on natural gas consumption patterns, on gas supply infrastructure, on future demand growth, and on potential changes gas markets resulting from power plant development in South Carolina.

The premise of the study is that power plant construction will follow an economic optimal path starting from today's conditions. This is important due to the large increase in gas demand fro power plants (14 percent per year on average). If more merchant plants are sited in states, the demand growth could be large and vice versa.

As gas demand increases, shortages can develop to the extent supply lags. This in turn can happen if customers lack firm gas supply. The effects are also exacerbated to the extent that gas users lack alternatives such as oil use. In California, few users had firm supply and few generators had fuel flexibility.

SOUTH CAROLINA NATURAL GAS MARKET OVERVIEW

Historically, South Carolina peak gas demand has occurred in winter, due to weather-dependent demand for residential and commercial heating. Despite the importance of residential and commercial demand, industrial users have consumed the majority of gas in South Carolina. Unlike residential and commercial demand, fluctuations in industrial demand are not weather related. Rather, industrial demand in South Carolina varies based on the cost of alternate fuels, such as distillate. Currently, gas demand for electric generation makes up only a small fraction of overall demand, but the sector is rapidly expanding. In South Carolina, gas-fired generation has met peak electric demand in the summer, so gas consumption for electric generation has fluctuated counter-cyclically to residential and commercial demand.

Two major interstate pipelines, Transcontinental Pipe Line Co. (Transco) and Southern Natural Co. (Sonat), serve South Carolina. The two interstate pipelines meet most South Carolina demand through transportation and storage services. The two primary customers of Transco and Sonat are South Carolina Pipe Line (SCPL), an intrastate pipeline, and Piedmont Natural Gas (Piedmont), a local distribution company. In addition to intrastate pipeline capacity, peaking LNG facilities also help meet South Carolina demand. In the future, increases in gas demand will be served by mainline expansions on Transco and Sonat and by reactivated LNG import terminals. Specifically, Elba Island gas will directly flow into South Carolina while Cove Point will displace gas south of the LNG terminal on Transco.

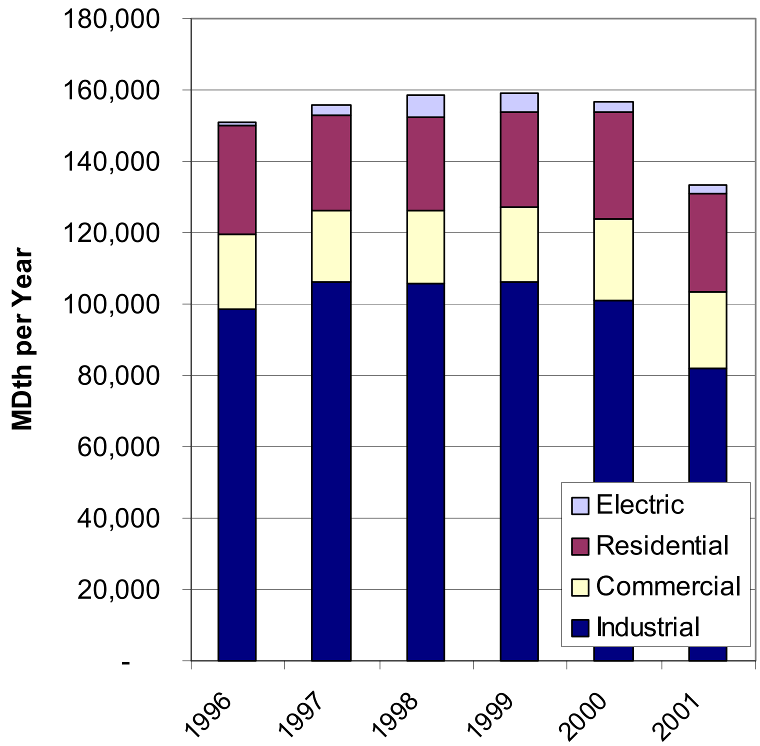
Overall, gas demand in South Carolina is forecasted to grow on average 5.6 percent per year from 189 Bcf in 2003 to 277 Bcf in 2010. Consumption by gas-fired generation will expand rapidly, beginning at around 39 Bcf in 2003 and growing by an annual average of about 20 percent per year through 2010. The near-term growth in gas consumption is a result of new merchant power plants being added to the grid. In addition, seasonal gas consumption patterns for electric generation are expected to change over time. The gas consumption for electric generation is expected to move away from summer peaking toward year-round gas consumption. The rapid increase in gas demand will require capacity expansion, both on the interstate pipeline system and from Elba Island. ICF estimates that additional pipeline capacity of 315 MMcf per day needs to be added by 2010 to meet the increased loads. The proposed expansions, in combination with peaking LNG, should be sufficient to meet peak winter demand.

NATURAL GAS CONSUMPTION PATTERNS IN SOUTH CAROLINA

In South Carolina, the residential and commercial sectors have, on average, made up around 18 percent and 14 percent of total gas demand, respectively. Historically, the industrial sector has been the primary user of natural gas in South Carolina user (over 60 percent of the total), although usage has fluctuated significantly. In 2001, for example, natural gas consumption in the industrial sector was around 19% lower than 2000 due to fuel switching.

Traditionally, electric utilities in South Carolina have consumed little natural gas. In future, however, natural gas consumption will increase due to merchant and utility power plant construction in the state.

Figure 5.1: South Carolina Annual Gas Consumption



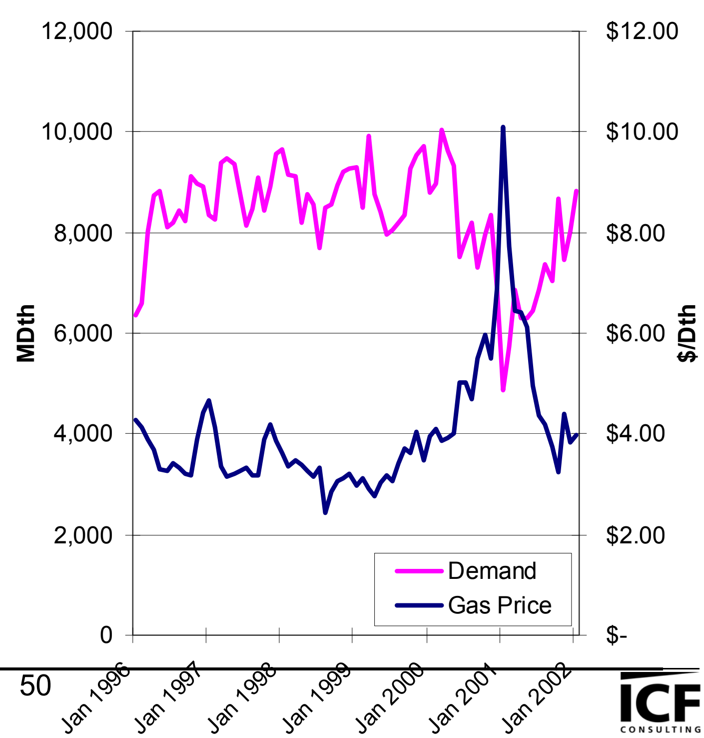
SOUTH CAROLINA INDUSTRIAL GAS CONSUMPTION

Natural gas demand in the industrial sector has been over roughly 65 percent of total gas demand in the state. In South Carolina, industrial demand fluctuates based on the price of alternative fuels, such as No. 2 fuel oil, and on economic factors.

Industrial demand dropped off significantly in 2001 but has bounced back. In January 2002, monthly industrial gas demand was 8,808 MDth, compared to 4,863 MDth one year earlier.

In the winter of 2000-2001, delivered gas prices for industrial users spiked, peaking at $10.14/Dth in January 2001 (compared with $6.86/Dth for distillate). There is no

Figure 5.2: South Carolina Industrial Gas Demand v. Delivered Gas Price

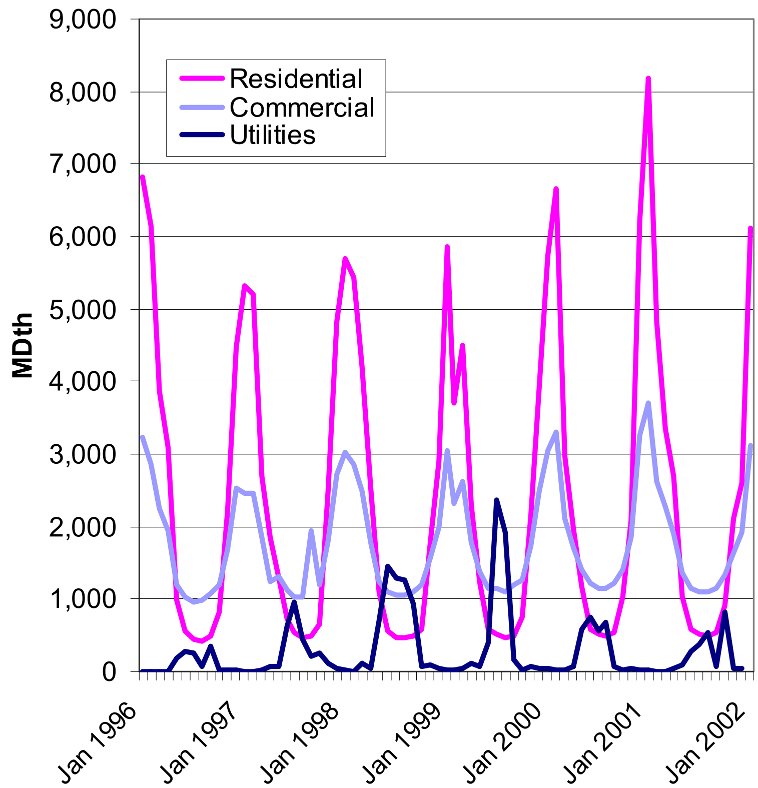


definitive seasonal variation in the industrial sector.

SOUTH CAROLINA RESIDENTIAL, COMMERCIAL, ELECTRIC GAS CONSUMPTION

Residential demand comprises approximately 18 percent of South Carolina's overall demand. It is highly weather dependent and is winter peaking. Annual residential demand has fluctuated from over 30,000 MDth in cold weather years (1996 & 2000) to around 26,500 MDth in normal weather years (1997-1999).

Figure 5.3: South Carolina Non-Industrial Gas Consumption



The commercial sector demand comprises approximately 14 percent of South Carolina's overall demand. Commercial demand fluctuates seasonally, although it varies less than residential demand and is winter peaking.

The electric generation sector natural gas demand in South Carolina is summer peaking. However, electric sector natural gas demand in South Carolina has historically been limited, with fossil electric generation dominated by coal and petroleum. In recent years, power plant development activities have resulted in a significant increase in the rate of natural gas demand from the independent power producer sector. Due to the recent addition of the Broad River facility, non-utility natural gas demand has outstripped utility sector demand. Continued additions by both utility and non-utility (merchant) developers are planned, and demand is expected to grow significantly.

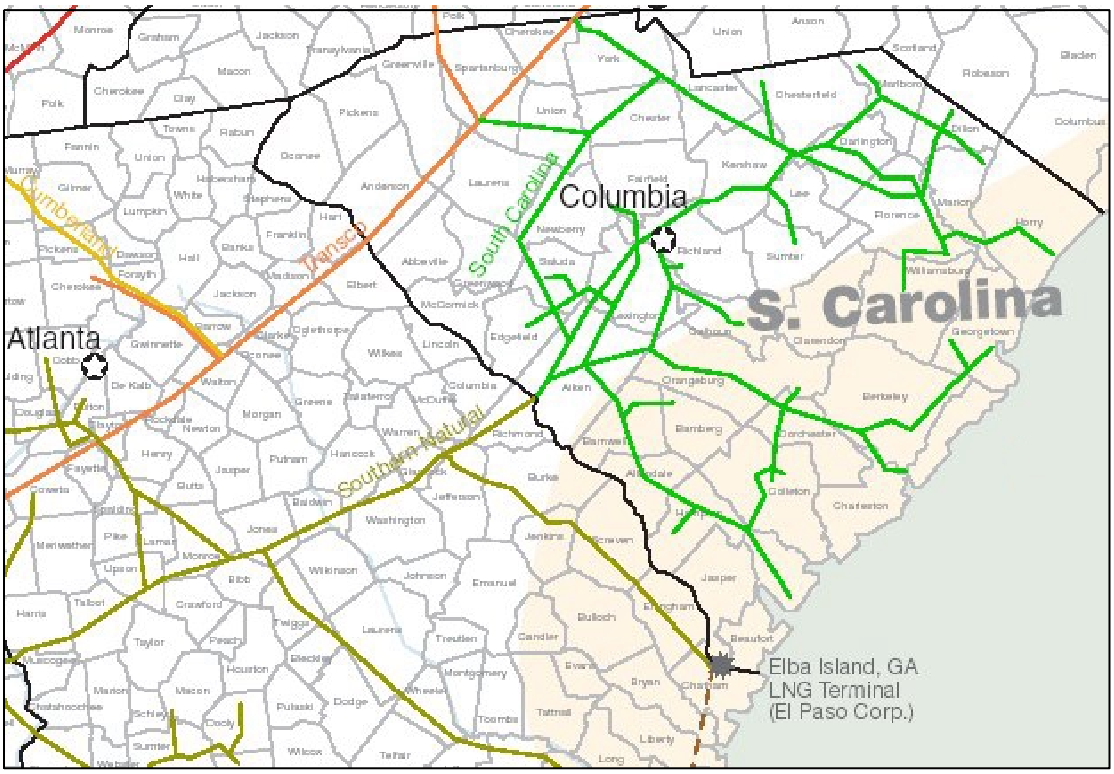
Table 5.1: Fossil Fuel Mix in South Carolina for Electricity Generation 2000 and 1999

	Total Electric		**Utility**		**Non-Utility**	
	2000	**1999**	**2000**	**1999**	**2000**	**1999**
Gas (Tbtu)	9.0	11.6	2.	5.3	6.1	6.3
Coal (Tbtu)	380.7	345.3	373.2	339.3	7.4	6.1
Petroleum (Tbtu)	4.5	5.3	4.2	4.7	0.3	0.6

SOUTH CAROLINA INTERSTATE GAS TRANSPORTATION

South Carolina has a unique gas transportation system. Two interstate pipelines, Transco and Sonat, serve a limited part of the state, bringing natural gas from U.S. Gulf to South Carolina. The Sonat system terminates in South Carolina while Transco terminates in New York and is a major pipeline serving the East Coast. In addition, Elba Island, an LNG import terminal located at the border of Georgia and South Carolina, was re-activated in December 2001.

Figure 5.4: Regional Gas Transportation Network



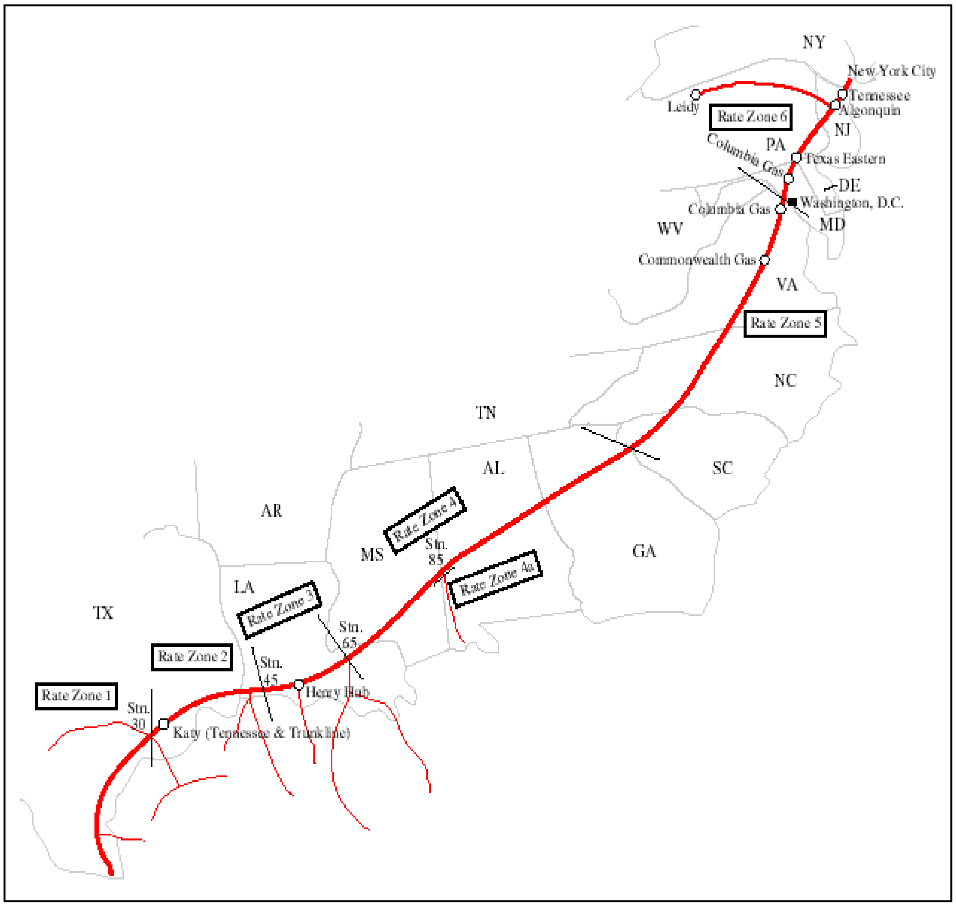
Within the state, South Carolina Pipe Line (SCPL) distributes gas on a bundled basis. SCPL sells bundled gas to industrial users and thirteen “sales for resale” customers, the largest of which is South Carolina Electric and Gas (SCEG), who then retail the bundled gas.

Transco, Sonat and Elba Island are all expanding to accommodate growth in the Southeast gas markets, so capacity appears to be available to serve new demand.

TRANSCO PIPELINE SYSTEM

Transco is a 10,560-mile interstate pipeline with a maximum design capacity of 7 Bcf per day. Transco transports gas supplies from the Gulf Coast to market areas in the east coast as shown. South Carolina is located in Zone 5 of the Transco system.

Figure 5.5: Transco Rate Zones



Entering the state, Transco had a total capacity of over 3 Bcf per day. South Carolina shippers have 356 MDth per day of contracted transportation capacity on Transco, a relatively small portion of the capacity.

According to FERC filings, Transco's maximum FT tariff from Henry Hub (Zone 3-5) is the following:

- Reservation (Min/Max): ($0.0411/$10.8898)/Dth/day/month
- Variable: $0/Dth
- Fuel: 3.31%

Transco offers several regional services to shippers in addition to FT. These include

- FT-G: Firm Transportation with "no release" clause

- ES/ESS: Eminence Storage Service (Eminence, Mississippi). ESS capacity release is managed by Williams Marketing & Trading, while ES is managed by the customer.
- WS/WSS: Washington Storage Service (St. Landry Parish, Louisiana). WS capacity can be released, while WSS cannot.
- LG-A: Liquefied Natural Gas Storage Service (Carlstadt, New Jersey)
- GSS: General Storage Service

Transco customers in South Carolina are presented on the table below.

Table 5.2: Transco Customer List

Transco Pipe Line Customers						
Customer Name	**MDth/d**		**MDth**			
	FT	**FT-G**	**ES/ESS**	**WS/WSS**	**LG-A**	**GSS**
South Carolina Pipe Line	109		55	1,294	10	76
Piedmont Natural Gas*	119		95	1,598		1,014
Fort Hill Natural Gas Authority	32			207	7	69
Clinton-Newberry Natural Gas Authority	16		37	414		
Commission of Public Works City of Greer	14		16			
Commission of Public Works City of Laurens	8		28	89		57
City of Blacksburg	3	7	5			
City of Fountain Inn	5	0.4	5			3
City of Greenwood	26		27	62	5	16
City of Union	11	6	12	48		46
TOTAL	**343**	**13**	**280**	**3,712**	**22**	**1,281**

*Assumes 25% of Piedmont capacity is allocated to South Carolina.
Source: FERC Form 549B (April 2002).

Historically, the Transco system has been over 80 percent full in South Carolina and flows have kept pace with expansions on the pipeline.

Table 5.3: South Carolina Interstate Pipeline Utilization

Name	**1998**	**1997**	**1996**	**1995**	**1994**	**1990**
Transco						
Anderson, SC	83.2%	84.3%	87.5%	84.2%	86.1%	89.2%
Cherokee, SC	83.4%	84.6%	87.9%	84.3%	86.7%	91.2%
Source: EIA						

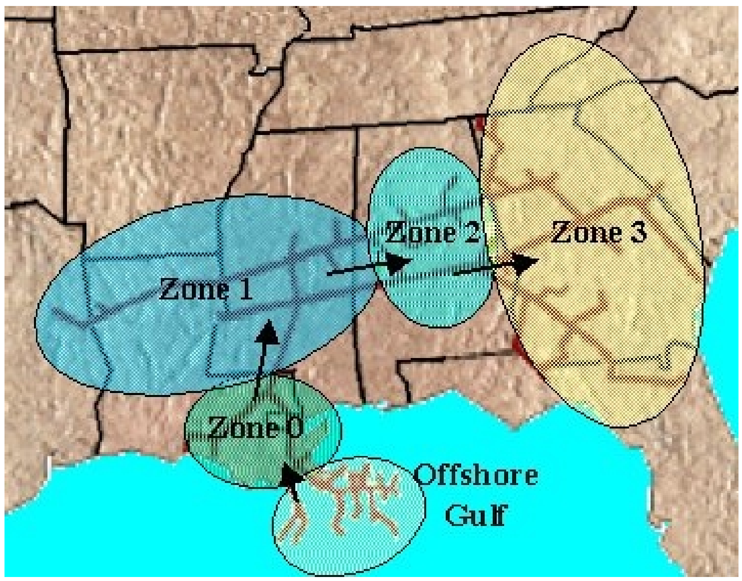
Zone 5 is not a highly active trading area, since much of the capacity is owned by utilities. Although capacity is available on the daily market, the utilities are unwilling to release large amounts of capacity for extended periods in the winter. The IT market has been liquid, even in the winter months.

Historically, Transco Zone 5 price has not been surveyed by Gas Daily, although the publication plans to begin publishing a Zone 5 price this summer. Zone 5 transportation trades at prices close to Zone 6 Non-New York prices in the summer. In the winter, Zone 5 trades at a discount.

SONAT PIPELINE SYSTEM

Southern Natural Gas (Sonat) pipeline is an 8,200-mile interstate pipeline with a design capacity of 2.8 Bcf per day. Sonat transports gas supplies from the Gulf to market areas in Southeast, particularly Alabama and Georgia. South Carolina shippers have 195 MDth per day of contracted transportation capacity on Sonat, roughly 75 percent that of Transco. Sonat terminates in South Carolina, so the capacity into the state and the contracted capacity are the same.

Figure 5.6: Sonat Rate Zones



According to FERC filings, Sonat's maximum FT tariff from Henry Hub (Production-Zone 3) is the following:

- Max. Reservation: $10.856/Dth/day/month
- Max. Variable: $0.0306/Dth
- Min. Variable: $0.0110/Dth
- Fuel: 2.6%

In addition to FT service, Sonat also offers shippers in South Carolina the following services:

- FT-NN: Firm Transportation Service - No Notice; and
- CSS: Contract Storage Service

Unlike Transco, Sonat has a limited number of customers with firm contracts, with SCANA Marketing and SCPL holding all FT contracts on the system. SCPL has roughly the same volume of firm contracts on Sonat as it does on Transco.

Table 5.4: Sonat Customer List

Customer Name	MDth/d		Dth
	FT	FT-NN	CSS
South Carolina Pipe Line	105	83	10,122
SCANA Energy Marketing	7		
TOTAL	**112**	**83**	**10,122**

Source: FERC Form 549B (April 2002)

Sonat delivers gas to South Carolina on an interruptible basis, up to 60,000 or 70,000 Dth per day. During winter peak days, IT into South Carolina drops to around 10,000 or 20,000 Dth per day. In general, the following two groups of users purchase Sonat IT: by South Carolina Pipe Line and by industrial users between Savannah and Aiken, which do not own FT.

Table 5.5: South Carolina Interstate Pipeline Utilization

Name	1998	1997	1996	1995	1994	1990
Sonat						
Aiken, SC	65.8%	64.4%	78.3%	88.1%	74.8%	72.4%

Source: Energy Information Administration

In general, the average utilization of Sonat declined from 1995 to 1998 and flows did not keep pace with capacity expansions on Sonat. However, new gas generation South Carolina will put pressure on the IT/released capacity market. The pricing in this market has historically traded roughly flat with the Atlanta city gate price.

PIPELINE EXPANSION AND LNG REACTIVATIONS

Capacity in South Carolina has expanded to meet anticipated demand. Transco is expanding mainline capacity in the Southeast through looping & compression. By 2003, Transco will add 762,000 Dth/d in new capacity and additional capacity additions are planned in year 2004. In South Carolina, 20,500 Dth/d of the planned expansions will supply LDCs and 60,000 Dth/d will supply power generators. Sonat is expanding capacity between compressor stations 65 and 165 through looping & compression. By 2003, Sonat will have added 584,000 Dth/d in new capacity.

Table 5.6: Capacity Expansions (Proposed & Under Construction)

Developer	Project	Type	Capacity (MDth/d)		In-Service	Filing Status
			Total	Into SC		
Sonat	South System I	Looping & Compression	325	50	June 2002	Filed
	South System II	Looping & Compression	259	158*	June 2003	Filed (CP00-233)
	Sonat Mainline	Looping & Compression	Unknown		Q2 2004	Will file
Transco	Sundance	Looping & Compression	236	16	May 2002	Filed
	Momentum	Looping & Compression	526	65	May 2003	Filed
	Cornerstone	Looping & Compression	Unknown		May 2004	Will file
Gulf Pipeline	Gulf Pines	New pipeline	967		2004	Not filed
SCG Pipeline	South Carolina	Extension	Unknown		Mid-2004	Not filed
	SCG Pipeline	Extension	Unknown		Nov. 2003	Filed

* SCG pipeline served by 93 MDth/d At Port Wentworth. Remaining 65 MDth/d for Calpine plant.
Source: ICF Consulting, Inc. research.

In addition, a new interstate pipeline, SCG Pipeline, Inc. (SCG) will transport gas to a new power plant in Jasper County, South Carolina. SCG will traverse through Chatham and Effingham counties. Its capacity is planned to be around 184 MDth/d, and it will interconnect with Sonat at Port Wentworth, Georgia and with Elba Island. In the future, SCG could be extended to SCPL. South System II will provide FT capacity of 93,000Dth per day at Port Wentworth to SCG. FT capacity at Elba Island is fully subscribed to El Paso.

Other projects are also under consideration. Gulf South Pipeline is considering a 1 Bcf pipeline from Mobile Bay to North Carolina. The announced in-service data is 2004. However, there have been no regulatory filings with FERC, suggesting that the project has stalled.

Table 5.7: South Atlantic LNG Import Terminals: Expansions and Reactivations

Project	Developer	Type	Capacity (MMcf/d)	Storage (Bcf)	Available
Cove Point, MD	Williams	Reactivation	750	5.0	Early 2003
		Expansion		+2.8	Mid-2004
Elba Island, GA	El Paso	Reactivation	440	4.0	Dec. 2001
		Expansion	+360	+3.3	June 2005
Radio Island, NC	El Paso	New Project	250	3.5	Undisclosed

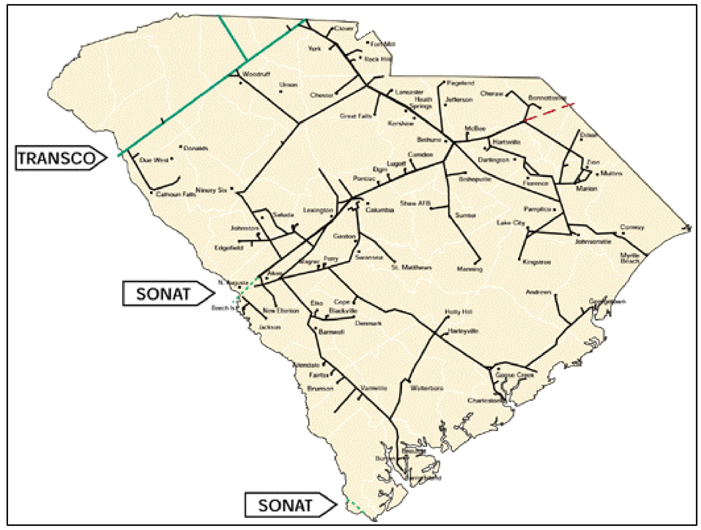
The Elba Island LNG import facility was recently reactivated. However, LNG imports at Elba Island do not directly provide gas to South Carolina. In the future, the planned SCG Pipeline will provide service from Elba to a new power plant in Jasper County, SC. According to SCANA, SCG Pipeline could also interconnect with SCPL, providing additional capacity to meet gas demand within South Carolina. Future expansions at Elba may provide additional capacity to other plants in southeast South Carolina. On a cost basis, Elba Island LNG competes with Gulf of Mexico gas on the Sonat pipeline, but future competition from other LNG facilities in the South Atlantic region is possible.

Intrastate Gas Transportation Network

South Carolina Pipeline (SCPL)

SCPL provides almost all intrastate gas transportation in South Carolina. SCPL consists of approximately 1,945 miles of transmission pipeline of up to 24 inches in diameter. SCPL brings 195 MDth/d on Southern Natural (expiring in 2005 and 2006). SCPL brings 109 MDth/d Transco (expiring in 2008 and 2017).

Figure 5.7: SCPL Pipeline Network



Source: Scana website (www.scana.com)

SCPL delivers gas bundled with transportation. Although SCPL recently attempted to unbundle transportation tariffs from commodity prices, the open season garnered less enthusiasm than expected. SCPL has withdrawn its open access tariff application with South Carolina's Public Service Commission. SCPL is not expected to provide unbundled transportation services in the foreseeable future.

On SCPL, bundled gas is available to the following three categories of customers:

- Firm demand: SCPL provides firm bundled gas to large customers, which is priced based on the following three components:
  - Demand charge: $7.20/Dth/day/month. (Subject to adjustment due to cost roll-ins.)
  - Max. Markup: $1.46/Dth
  - Weighted average cost of gas (WACOG)
  - Surcharge for associated losses & compressor fuel (≈ 1.42%).
- Interruptible demand: Under the Industrial Sales Program (ISPR), most industrial customers receive gas on an interruptible basis. Gas is priced with respect to the alternative fuel, subject to a cap of $0.66/Dth plus the commodity cost.
- "Sales for Resale" demand. SCPL sells gas to 13 retailers, who act as local distribution companies and resell gas primarily to residential customers. As described above, the retailers can either purchase gas on a firm basis or under ISPR for qualifying customers.

The list of FT capacity of "Sales for Resale" customers is shown in Table 5.8.

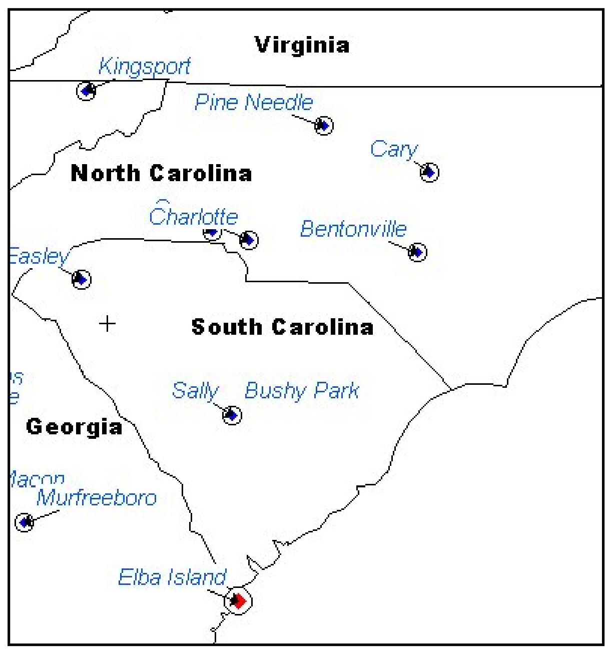
Table 5.8: "Sales for Resale" FT Capacity Customers on SCPL

Name	Dth per day
SCE&G	276,495
Patriot's Energy Group	
Chester County Natural Gas Authority	8,000
York County Natural Gas Authority	26,000
Lancaster County Natural Gas Authority	8,400
Orangeburg Department of Public Utilities	8,200
The City of Union	500
Winnsboro Natural Gas Department	1,558
Bamburg Board of Public Works	1,200
Bennettsville Municipal Gas Department	2,306
Clinton-Newberry Natural Gas Authority	2,000
Fort Hill Natural Gas Authority	3,000
Commission of Public Works City of Greer	500
Shaw Air Force Base	974
Total	**339,133**

Source: SCPSC Docket No. 90-204-G

PEAKING LNG

Figure 5.8: Regional LNG Facilities



In addition to interstate pipelines, peaking LNG facilities help meet South Carolina peak demand. The Pine Needle facility in Guilford County, North Carolina, is the largest peaking LNG facility available for indirectly meeting peak demand in South Carolina.

The largest peaking LNG facility that is available for meeting peak demand in South Carolina is the Pine Needle facility in Guilford County, North Carolina. Pine Needle has a vaporization capacity of 400 MMcf/d. Piedmont Natural Gas provides peaking service through displacement from Pine Needle.
South Carolina also has the following three LNG peaking facilities:

- Easley in Pickens County (12 MMcf/d)
- Salley in Orangeburg County (90 MMcf/d)
- Bushy Park in Orangeburg County (60 MMcf/d)

LOCAL DISTRIBUTION COMPANIES

In South Carolina, South Carolina Electric & Gas (SCEG) and Piedmont Natural Gas (Piedmont) are the primary local distribution companies.

SOUTH CAROLINA ELECTRIC & GAS (SCEG)

SCEG's natural gas system consists of approximately 12,793 miles of distribution mains and related service facilities. The service area encompasses all or part of 33 of the 46 counties in South Carolina. Service area population is approximately 2.6 million. Service area encompasses 22,000+ square miles. Industrial customers include: synthetic fibers; chemicals; fiberglass; paper and wood; metal fabrication; stone, clay and sand mining and processing; and textile manufacturing.

Table 5.9: South Carolina Electric & Gas Annual Sales (MDth)

Annual Sales (MDth)			
	2001	**2000**	**% Change**
Residential	11,256	14,506	(22.4)
Commercial	11,305	12,817	(11.8)
Industrial	14,301	17,129	(16.5)
Transportation Gas	2,461	2,085	18.0
Total	**39,323**	**46,537**	**(15.5)**

SCEG serves roughly half the gas demand in South Carolina. SCEG recorded a net increase of approximately 800 gas customers during 2001, increasing its total customers to approximately 267,200. SCEG holds FT of 276,495 Dth per day on SCPL. In addition to LNG facilities discussed previously, SCEG also has propane air facilities, which can store the equivalent of 325 MMcf of natural gas and gasify the equivalent of 73 MMcf per day.

In 2001, SCEG's residential sales accounted for 44 percent of gas sales revenues; commercial sales 33 percent; and industrial sales 23 percent.

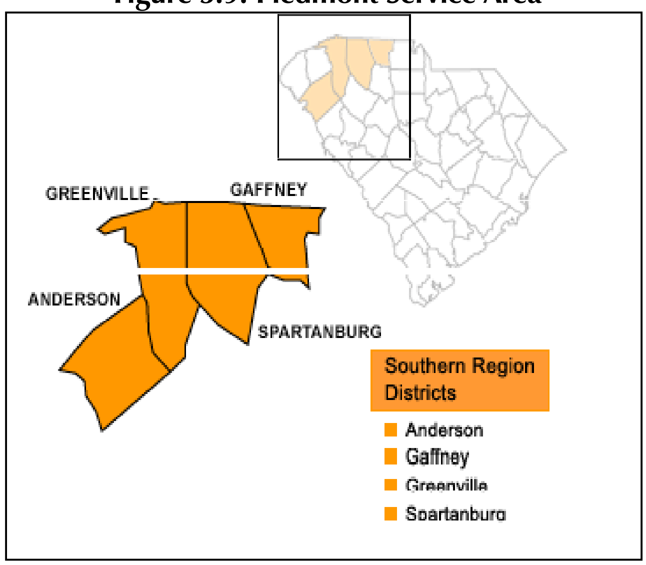
According to SCANA's Annual Report for 2001,"For the three-year period 2002-2004, the Company's total consolidated sales of natural gas in DTs are projected to increase 1.5% annually. Residential DT sales are projected to increase 2.6% annually, commercial sales 2.7%, industrial sales 1.0% and sales for resale 0.0%. The Company's total consolidated natural gas customer base is projected to increase 2.9% annually."

PIEDMONT GAS & OTHER LOCAL DISTRIBUTION COMPANIES

Other than SCPL, Piedmont Natural Gas is the only other intrastate pipeline in South Carolina. Piedmont delivers gas from Transco to four counties in South Carolina, shown below. Piedmont also delivers gas to North Carolina and Tennessee.

Other local distribution companies deliver gas to smaller markets. Patriot Energy Group is considering expanding its intrastate pipeline to Transco, in order to bypass SCPL. The $37 million, 60-mile pipeline would have a capacity of 150 MMcf per day and has a proposed in-service date of year-end 2003. The pipeline is not moving forward at this time.

Figure 5.9: Piedmont Service Area



NATURAL GAS DEMAND FORECAST

SOUTH CAROLINA TOTAL GAS DEMAND

Table 5.10: South Carolina Demand (Bcf per year)

	2003	2004	2005	2006	2008	2010
Residential	24.9	24.9	25.3	25.5	25.6	25.9
Commercial	25.7	26.0	26.6	27.0	27.6	28.3
Industrial	98.5	83.3	92.6	114.4	106.3	13.1
Electric Generation	39.4	63.8	73.7	64.9	92.8	119.7
Total	**188.5**	**198.0**	**218.3**	**231.8**	**252.2**	**276.9**

Source: ICF Consulting.

Within South Carolina, residential and commercial demand is expected to grow modestly. Residential demand growth is expected to average 0.6 percent through 2010, and commercial demand will grow faster, averaging 1.4 percent. Industrial growth will be slower at 0.6 percent annually and industrial users will compete for natural gas with new electric generators.

Electric demand is expected to grow robustly. The share of gas consumption for electric generation will increase to 43% of total demand by 2010. In the near-term, gas consumption is expected to jump immediately as plants currently under construction become available.

Table 5.11: South Carolina Seasonal Gas Consumption (Bcf)

	2003	2004	2005	2006	2008	2010
Winter	7.0	14.5	19.1	16.5	21.4	29.7
Summer	22.1	30.9	30.2	28.4	34.0	42.1
Shoulder	4.5	6.6	13.3	9.2	20.7	27.3
Other	5.7	11.7	11.1	10.9	16.8	20.6
TOTAL	**39.4**	**63.8**	**73.7**	**64.9**	**92.8**	**119.7**

Seasonal Percentage of Total Demand						
Winter	17	22	25	25	22	24
Summer	54	47	40	42	35	34
Shoulder	11	10	17	14	22	22
Other	14	18	15	16	18	17

Natural gas consumption in electricity generation has been grouped in four seasons.

- Winter: January, February, December
- Summer: June, July, August
- Shoulder: March, April, October, November
- Other: May, September

By 2010, gas-fired generation will move from only summer peaking to consuming gas year-round. Summer peaking decreases from 58 percent to 36 percent of total consumption, winter peak increases from 18 percent to 26 percent.

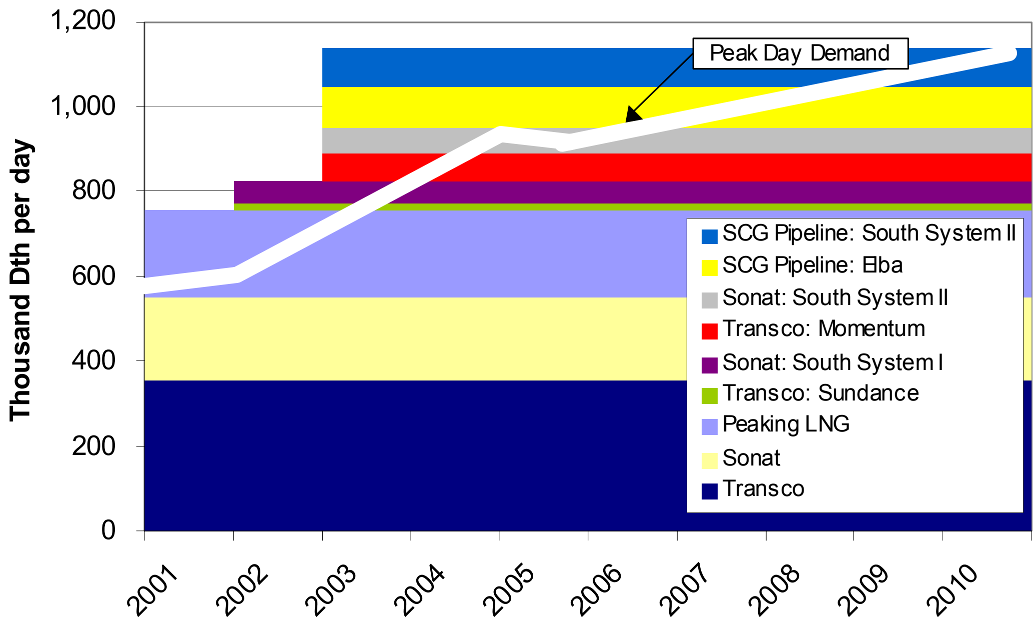
Natural Gas Transportation Forecast

Table 5.12: South Carolina Gas Transportation

	2003	2004	2005	2006	2008	2010
Flows (MMcf/d)						
From Elba Island	8	32	182	182	194	194
From US Gulf	511	517	419	454	503	575
Capacity (MMcf/d)						
From Elba Island	25	33	183	183	200	200
From US Gulf	518	518	518	518	542	633

Gas consumption from new generation will put pressure on transportation to the state. ICF expects the demand for new generation to be met by capacity expansions from Elba Island, Sonat and Transco. Market growth in South Carolina is increasingly met by Elba Island supplies via SCG Pipeline and is expected to expand to 200 MMcf per day by 2008. Sonat and Transco are expected to expand an additional 115 MMcf per day by 2010. Supplies from Elba Island will back out Gulf gas. For the required 315 MMcf per day of new capacity, Elba Island, Sonat and Transco will compete on a full cost basis.

Figure 5.10: Announced Capacity & Peak Demand Forecast



Announced expansions totaling 368 MMcf per day are adequate to meet increased peak demand, however, not all announcements are yet considered firm. In 2004, additional capacity will be available from Transco and Sonat expansions, although details are not yet available. Through additional compression, SCG Pipeline capacity may also be expanded. ICF modeling shows that peaking LNG will also need to expand to meet the peak demand.

Findings and Conclusions

As a result of this analysis of the gas infrastructure in South Carolina, ICF presents several finding and conclusions regarding the industry.

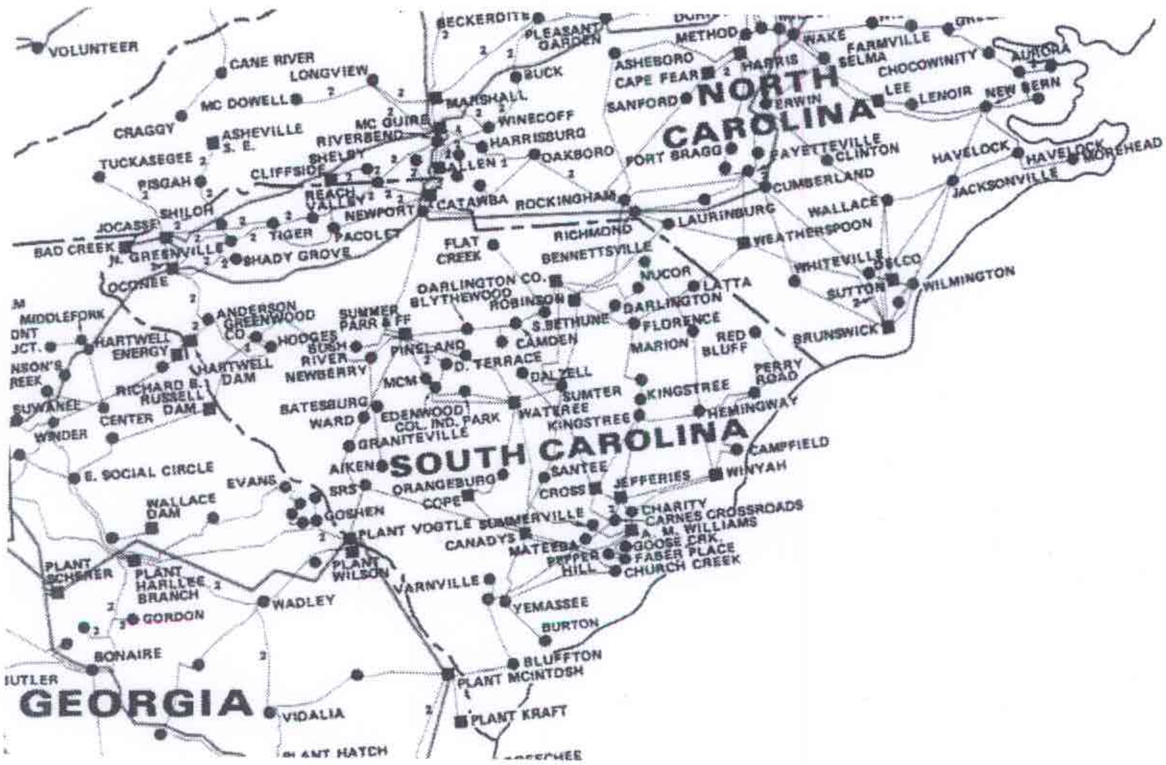
- **Natural Gas Consumption Patterns** – Natural gas consumption in South Carolina for electricity generation will grow by 14% per year through 2010. Natural gas consumption in South Carolina for non-electric sectors will grow by less than 1% per year through 2010.
- **Peak Demand** – Natural gas peak demand will grow by over 5% per year. There will be a rapid increase in peak gas demand in the electric sector due to increased gas-fired generation in the winter months.
- **Interstate Pipeline Capacity** – For the next ten years, pipeline capacity into South Carolina will need to expand by at least 315 MMcf per day to meet increased merchant power generation growth. Announced expansions total 368 MMcf per day. The growth in the overall natural gas market in South Carolina indicates that Transco and Sonat pipelines will continue to expand. In addition, SCG pipeline will provide additional natural gas from Elba Island and through its interconnection with Sonat.
- **LNG** – Elba Island supplies will back out Gulf gas into South Carolina. Re-activation of Cove Point will provide additional supplies into South Carolina through displacement on Transco.
- **Reliance on Firm Supply** – A check on the extent to which current users rely on firm supply or have back-up fuel alternatives may be in order.

CHAPTER SIX: ELECTRICITY TRANSMISSION IN SOUTH CAROLINA

South Carolina's Transmission Network

The bulk power transmission facilities of South Carolina comprise a 230 kV backbone, and a network of 115–100 kV and 69 kV lines. The 230 kV network is the lowest transmission backbone of any state in the US in terms of voltage. The only exception is the 500 kV lines along the northern and northwestern extremities of the state.

Figure 6.1: Physical Layout of 230 kV Transmission System in South Carolina



Since transmission capacity increases with transmission voltage, arguably the capacity of South Carolina's bulk power transmission infrastructure is also relatively low compared to other states. We note, however, this theoretically can be offset by greater density of lines. Table 6.1 shows a comparison of the primary and secondary transmission voltage backbones and their approximate capacities[1] for a selected number of states in the US. Thus bulk power flows from the Northeast (Pennsylvania and Virginia) to the Southeast (Georgia and Florida) and vice-versa are transmitted via the interconnected 500 kV systems in Tennessee and North Carolina. This is explained in part by the limited throughput of the 230 kV system of the South Carolina Grid.

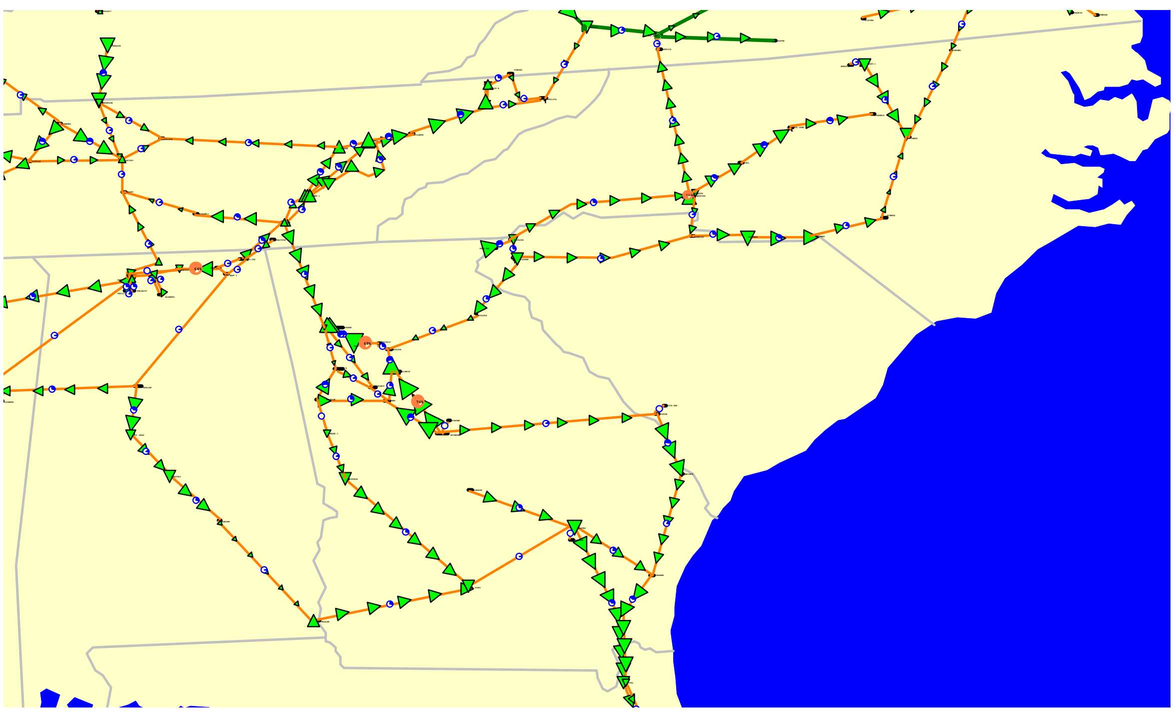
Table 6.1: Primary and Secondary Transmission Voltages of Selected States

State	Primary Transmission Backbone		Secondary Transmission Backbone	
	Voltage (kV)	Approximate Capacity* (MVA)	Voltage (kV)	Approximate Capacity* (MVA)
South Carolina	230	320 – 800	115	320-50
North Carolina	500	1,400 – 3,100	230	320 – 800
Virginia	500	1,400 – 3,100	230	320 – 800
Georgia	500	1,400 – 3,100	230	320 – 800
Tennessee	500	1,400 – 3,100	115	320-50
Ohio	765	3,100 – 5,000	345	800 – 1,400
Florida	500	1,400 – 3,100	230	320 – 800
PJM	500	1,400 – 3,100	345 & 230	320 - 1400

* The capacities presented here are for individual lines of different conductor sizes

Figure 6.2 shows a projected summer 2002 snapshot of power flows on the high voltage 500 kV bulk power transmission systems in the Southeast regions.

Figure 6.2: Physical Layout of 500 kV Transmission System in the Southeast

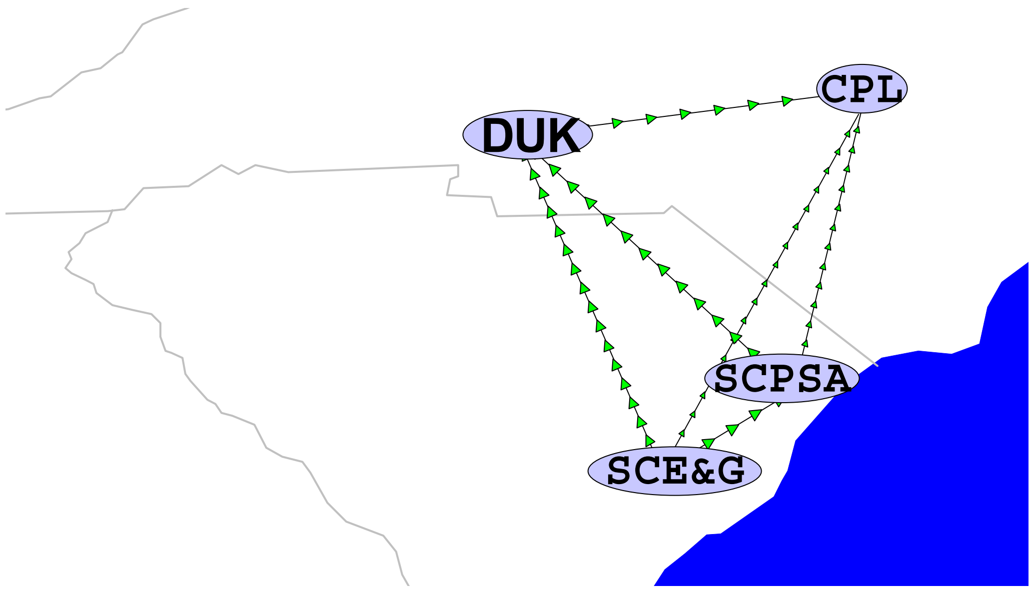


[1] These approximate capacities represent individual lines of various conductor thicknesses. They do not refer to potential transfer capabilities across selected interfaces

Control Areas

Four Control Areas[2] serve load in South Carolina. These Control Areas are Duke, South Carolina Electric & Gas (SCE&G), South Carolina Public Services Authority (SCPSA) and Carolina Power and Light (CPL). Transmission ties exist among these control areas for economy and emergency power sales and for grid reliability. Figure 6.3 shows that under a projected 2002 summer peak base case condition, power flows from Duke, SCE&G and SCPSA to CPL, Duke imports power from SCE&G and SCPSA and SCPSA imports power from SCE&G. These control areas also interchange power with other control areas external to South Carolina such as Virginia Power, AEP, TVA and Southern Company. As such, South Carolina is a net exporter in this "snapshot" scenario.

Figure 6.3: Diagram of Interconnected Control Areas Serving Load in South Carolina



Together, these four Control Areas serve a total of about 16 GW of load. Duke serves a peak load of approximately 5.5 GW, SCEG and SCPSA serves approximately 4.5 GW and 4 GW respectively and CPL serves approximately 1.5 GW. With the exception of SCPSA, each Control Area has sufficient installed capacity to serve load but with varying degrees of reserve margin capacity to meet reliability requirements. Implied reserve margins determined from Figure 6.4 shows a margin of approximately 39% for Duke (South Carolina) and 15% each for CP&L (South Carolina) and SCE&G. SCPSA has a peak capacity deficit of approximately 2%. Thus, SCPSA would need power imports from neighboring control areas especially during peak conditions to meet its reliability and reserve margin requirements.

[2] A Control Area is a geographic footprint where generation is dispatched to balance load in real-time.

Figure 6.4: Load vs. Installed Capacity by Control Area (South Carolina Only) - 2002

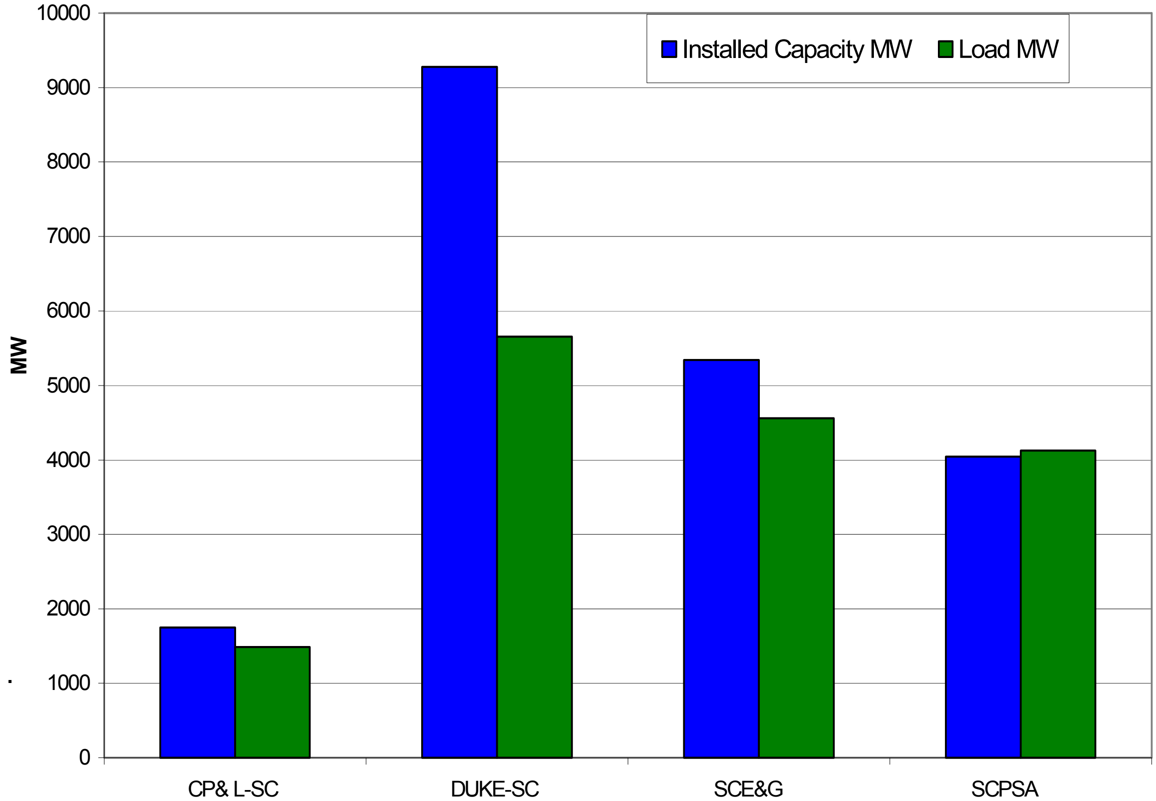
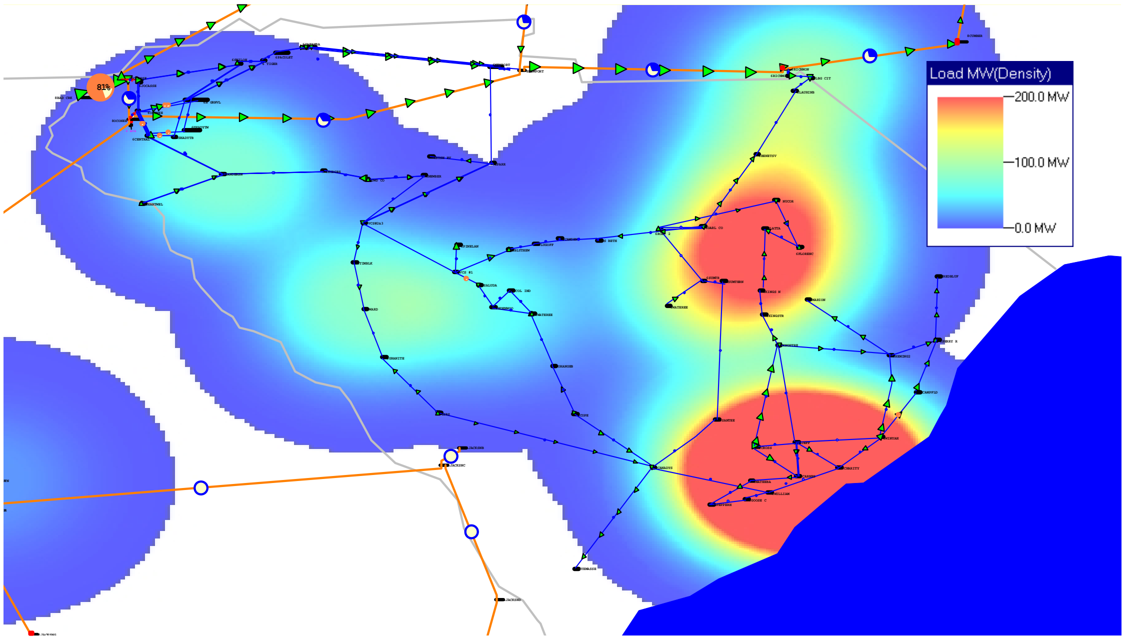


Figure 6.5 shows the location and distribution of loads. Load densities are highest in the southeast. Thus, although Duke has a higher share of load in the state, it probably has the lowest load density. SCPSA serves load in the southeast.

Figure 6.5: Load Distribution and Density in South Carolina



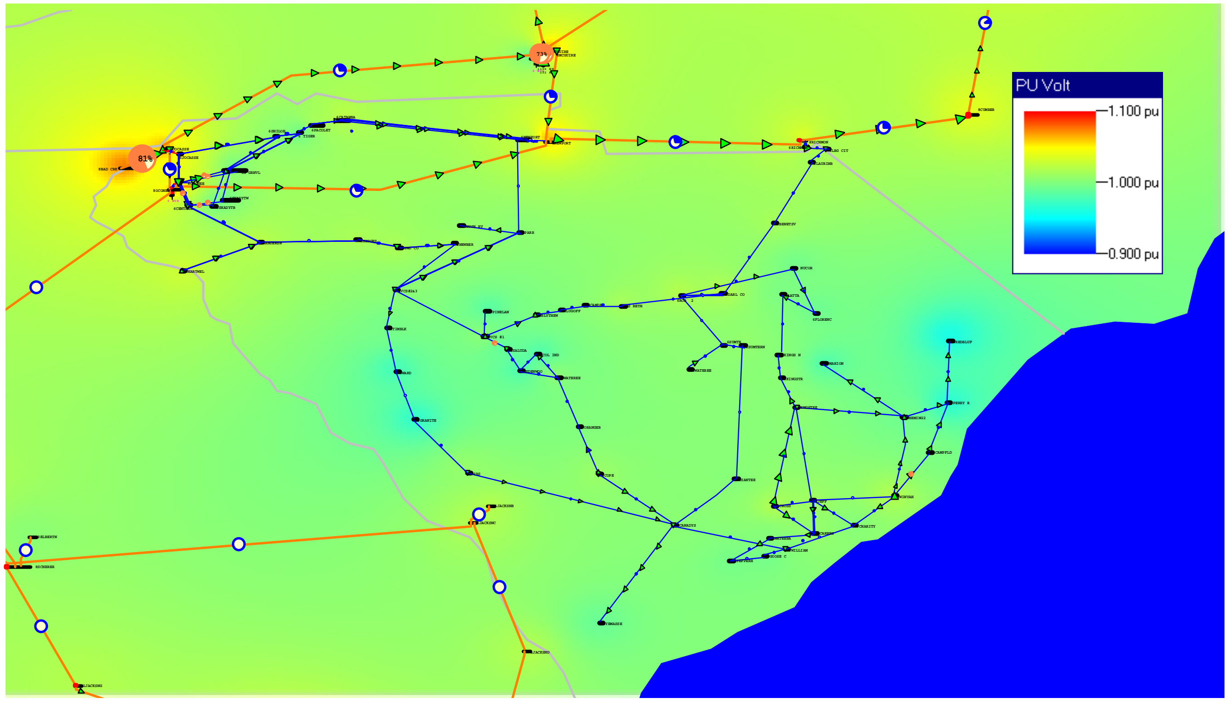
Existing Condition of the Transmission System

ICF performed a base case 2002 summer peak simulation of the South Carolina network to examine the condition of the grid. The goal of the exercise was to identify potential voltage limitations and transmission facility overloads. Secondarily, we wanted to identify all transmission facilities 80% loaded or higher.

With the assumption of all transmission facilities in service, all voltages were found to be within their statutory limits[3]. System operators are required to regulate all nodal voltages within their statutory limits during operations of the power system. When voltages fall outside their statutory bounds, system operators run the risk of disruptions in the supply of power from generators to loads. In order to avoid this risk, system operators take remedial action to regulate voltage by either boosting voltages or lowering them to meet compliance requirements. Figure 6.6 shows a profiling of simulated nodal transmission voltages.

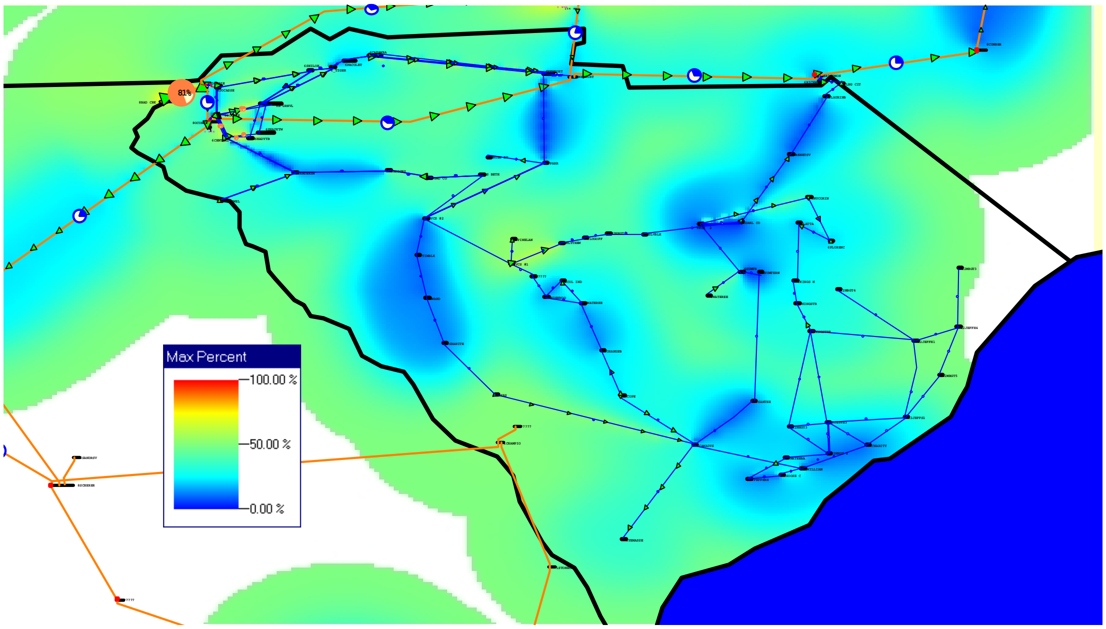
[3] The Statutory limits are -5% to +5% of the standard nodal voltage during normal operations and –10% to +10% during contingency conditions

Figure 6.6: A Contouring of Voltage Conditions for a Representative 2002 Summer Peak Simulation of the South Carolina Transmission Network



In our analysis we allowed acceptable transmission voltages to be within 10% of their nominal values i.e. at their contingency limits. This implies that for a 230 KV transmission voltage, the range of acceptable contingency voltages should be within 207 kV and 243 kV. None of the nodal voltages within South Carolina are severely over or under the required limits, thus the bulk of transmission voltages within South Carolina are within acceptable contingency voltage ranges.

Figure 6.7: A Contouring of Loading of Major Transmission Facilities for a Representative 2002 Summer Peak Simulation of the South Carolina Transmission Network



There were no transmission facility overloads under base case conditions. Figure 6.7 shows a contouring of line loadings of the major 230 KV lines. The contour map shows all lines to be within their limits.

The table below shows lines that were loaded at 80% of their Normal[4] limits. None of the 230 kV lines were loaded above 80%. Thus, with the exception of one 500 KV line which is close to South Carolina, these heavily loaded lines are all either 115kV or less. The lines loaded above 80% were mostly in Duke and SCPSA and they represent about 2 % of all lines above 69 kV in South Carolina. Nonetheless they could be very crucial and limit power transfer capability across major transmission corridors.

[4] Lines usually have three limits i.e. Normal, Contingency and Emergency limits. Contingency and Emergency limits are usually higher than Normal limits but can only be used for shorter time periods. Our base case simulation considered only Normal line limits.

Table 6.2: Transmission Facilities With Loadings at 80% or Higher

Interconnecting Nodes		Control Area(s)		Line Voltage (kV)	Line Limit* (MW)	Line Flows* (MW)	Percent Line Loading
From	TO	From	To				
Cope	Orangeburg	SCPSA	SCPSA	69	37	-32	87
Flat Creek	Jefferson	SCPSA	SCPSA	69	37	36	99
Newport	Wylie Hydro	Duke	Duke	100	156	155	99
Newport	Wylie Hydro	Duke	Duke	100	156	155	99
Hodges	Greenwood	Duke	Duke	100	97	-92	94
Bad Creek	Jocasse	Duke	Duke	500	1,559	1,398	90
Chester	Newport	Duke	Duke	100	97	-84	86
Newberry	Prospect	SCPSA	SCPSA	100	37	32	86
Cherokee	Gaffney	Duke	Duke	100	107	93	86
Conway	Singleton Ridge Road	SCPSA	SCPSA	115	95	82	86
St Stephen	Kingstree	SCPSA	SCPSA	115	95	81	85
Newberry	Stonev	SCPSA	SCPSA	69	30	37	82
Anderson	Toxaway	Duke	Duke	100	113	92	81
Anderson	Toxaway	Duke	Duke	100	113	92	81

* These measures are technically measured in MVA – mega-voltage-amperes, but for the purposes of the intended audience we have conveniently converted them to MW for simplicity i.e. MW =MVA*0.9.

The analysis so far assumes all transmission facilities in service. However, under contingency conditions, some transmission facility overloads and thermal limit violations were identified. These are discussed in the next section.

Commercially Significant Transmission Constraints

There are significant transmission constraints that limit bulk power transfers within South Carolina. These constraints have the tendency to segment the power markets and create sustained power price differentials for several hours. Some of the transmission constraints are:

- The 230 kV line from Beckerdite to Belews Creek
- The 230 kV/100 kV Hodges Circuits 1 and 2*
- The 100 kV line from Hodges to Belton
- The 230 kV line from Hodges to Greenwood County*
- The 230 kV/69 kV Darlington transformer*
- The 230 kV lines from Harrisburg to Oakboro
- The 100 kV line from Great Falls to Wateree
- The 230 KV lines from Segars Mill to Darlington
- The 230 kV line from Catawba to Newport
- The 230 KV line from Vogtle-Savannah River Services (VCS) to Blythewood
- The 230 kV line from Vogtle-Savannah River Services (VCS) to Parr

* Monitored by NERC as a flowgate

Expected Generation Capacity the Network Can Withstand Without Substantial Upgrades

We performed a preliminary analysis to estimate the incremental capacity over projections for 2002 that the existing transmission network can reliably accommodate. This kind of analysis is subjective because exogenous decisions will have to be made about the locations and quantities of generation injections. These assumptions are crucial to the outcome of such an analysis. We approached the problem by simultaneously increasing generation and discrete loads. We increased generation by (i) activating all off-line units and (ii) postulating the completion of some of the announced projects. We activated a total of 930 MW of units that were originally designated as off-line and 1,700 MW of new injection. We increased existing discrete loads by a total 2,100 MW. This 2,100 MW of load represents about 5-7 years of load growth. Beyond this level of combined load growth and megawatt injection, the model cannot provide a system solution. Thus the system can be assumed to be capable of absorbing up to 2,700 MW, beyond which substantial investments would be needed to reinforce the transmission system to maintain security and adequacy of the network.

Conclusion

Our near-term (1 to 5 years) analysis of the network shows that there are no major transmission problems especially when all facilities are assumed to be in-service. Although our 2002 simulation of the network shows reasonable adequacy in the near-term, we believe that the existing transmission network may not be able to support another 2.7 GW of growth without substantial transmission reinforcement. This suggests that under certain circumstances, the system can be stressed and will require some attention.

Although there are some critical contingencies that limit transmission transfer capabilities between control areas, there are potential remedial actions that can be taken to mitigate such circumstances to keep the system in operation. Going forward, with increasing load growth, remedial actions may not be able to provide the required level of system security.

CHAPTER SEVEN: MODELING SOUTH CAROLINA POWER INDUSTRY

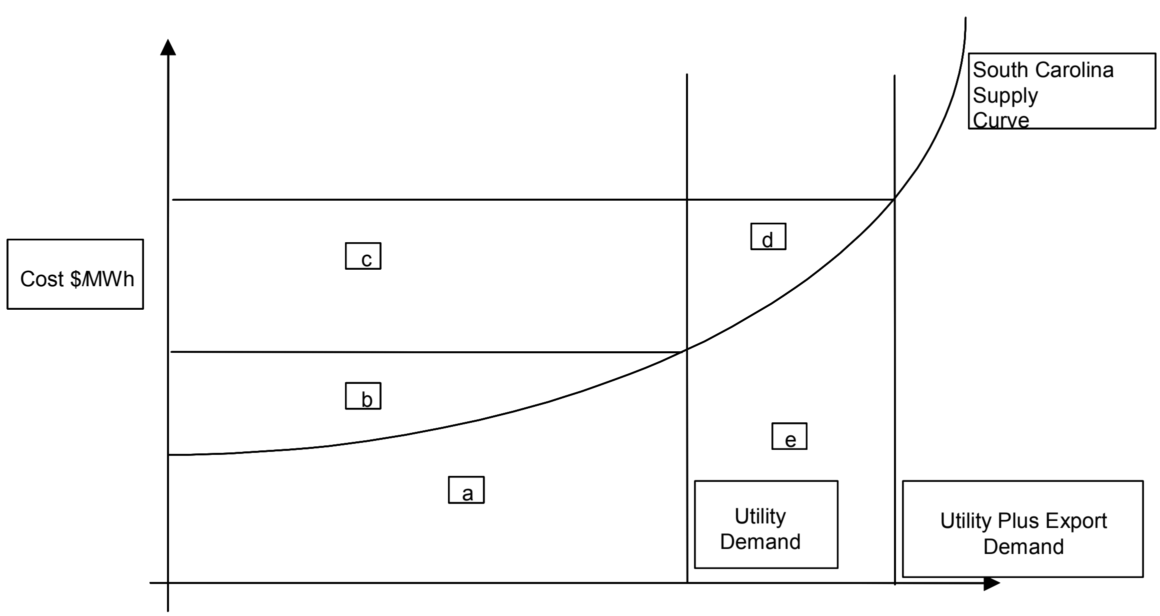
INTRODUCTION

The state of South Carolina faces several issues in light of deregulation. These include how to determine the need for Merchant plants, and potential impacts on electricity and gas transmission systems. This chapter provides some quantification around trends in the South Carolina power industry.

Even in the event that no merchant plants are built in the state, transmission can play a large role in the costs of generation to meet load. In the attached graphic, we consider a situation in which an exporting state with regulated in-state generation is affected by exports, a case which may be relevant for South Carolina. The cost of meeting utility load is area [a]. If the utility can export to other buyers, demand increases from D (utility) to D (utility plus export). Though the utility's costs increase by area [e], the utility revenues increase by [d] plus [e]. Thus, the utility can defray the costs of serving utility customers by [d], Areas [c], [b], and [d] would be profit except by regulation consumer costs are limited to [a] – [d].

In addition, as demand increases, gas consumption could increase.

Figure 7.1: Utility Costs and Exports



Scenarios which illustrate the magnitude of transmission effects include:

- **Extreme Isolation** - As an extreme example of impact on generator costs and consumer prices, we evaluate a case which isolates South Carolina from all other states. Local generation resources are allowed to only serve local markets and purchases from external states are not allowed. Note this case excludes all transactions across state borders.

- **South Carolina Limited to Exchanges within Local Control Areas** - Currently in South Carolina, there are two utilities with multi-state control areas, Duke and Carolina Power and Light. Both utilities serve both North and South Carolina and have service territories that overlap these two states. As such, the generation resources owned by Duke in South Carolina, can easily supply load support to load areas in North Carolina and vice versa. Transmission limitations across state borders within the same control are generally very high and not restricting. Given the strong relationship across states within the control areas, a complete isolation case would be highly unlikely. As such we analyze a more realistic case isolating South Carolina only from utilities entirely outside of South Carolina. As such, South Carolina is isolated from the Southern region and TVA in this case, but may still connect with route exchanges through the North Carolina portions of Duke and CP&L.
- **Base Case** – Transmission is assumed to pay tariffs for movements between regional markets.
- **Mid-Atlantic ISO Expansion** - Although the Base Case considers de-pancaking of transmission rates throughout the large Eastern Interconnect, it does not capture the impact of the realignment of companies from one group or affiliation to another. A change in affiliation should result in an increase of efficiency between the new organization, thereby lessoning transaction costs, while increasing transaction costs to former affiliates. For example, if PJM West utilizes the same transaction management system as PJM, trading will be transparent while additional transaction costs may occur given ECAR neighbors remain on an alternate transaction management system. Currently, it is likely that the PJM West ISO organization will expand further west resulting in more transactions between companies like Allegheny and Duquesne while decreasing transactions between Allegheny and the rest of ECAR. The Mid-Atlantic ISO case differs from the Base Case through capturing the larger PJM West structure. Other possible shifts include Entergy, TVA and Virginia Power aligning with organizations outside of the current SERC reliability region. We isolate this case as the most likely to occur structural change.
- **FERC RTO Proposal** - FERC expects the formation of RTOs to result in improvements in the functioning of power markets due to better utilization of the transmission infrastructure. The FERC proposal calls for three large RTOs in the Eastern Interconnect: the Northeast, the Southeast, and the Midwest. We have followed this division bringing our total transmission areas down from 10 in the Base Case.

Table 7.1: Scenarios Examined

Scenario Examined	Transmission Limitations	Tariffs
Base Case	Transfers based on ICF TTC analysis	Tariffs between 10 regions in the Eastern Interconnect
Extreme Isolation	No transfers out of or into state; no charge to intra-state units	Intra-state tariffs maintained from Base Case
Local Control Areas	Out of state transfers limited to Duke and CPL territories	Same as Base Case
FERC RTOs	TTCs increased 5 percent	Tariffs only between 3 large RTOs in the Eastern Interconnect
Mid-Atlantic ISO Expansion	Same as Base Case	Number of regions same as Base Case, however, regional configuration modified
Demand Growth	Same as Base Case	Same as Base Case
Site Depletion	Same as Base Case	Same as Base Case

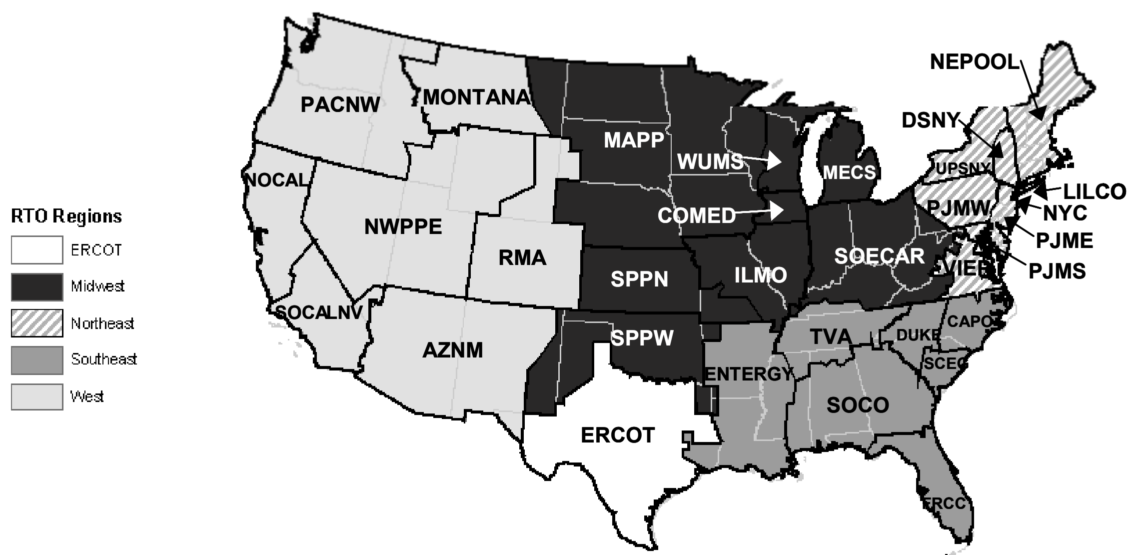


Figure 7.2: FERC Suggested Regional RTO Structure

In addition to the reduced transaction costs considered in the Base Case, the FERC RTO Case incorporates additional benefits likely to occur under the broad regional management of the transmission grid including:

- Transmission transfer capability expansion: RTOs may lead to greater incentives for transmission investment and improved regional planning. This is captured through increasing the effective transfer capability of transmission links among sub-regions within an RTO by 5 percent beginning in 2004. Transfer capabilities between RTOs are consistent with Base Case assumptions.

- Reserve margins: Larger RTO regions will be able to pool reserve resources more effectively, leading to reduced reserve margin requirements. We assume a 2 percent decrease from required Base Case reserve margin levels beginning in 2004.

- **Merchant Plant Contractual Obligation Case** - As a potential policy decision, the Public Service Commission of South Carolina is considering requiring independent power producers to negotiate power purchase agreements with incumbent utilities. ICF has considered this requirement from the seller and buyer perspective.

  On the sell side, the primary concern of an independent power producer is the financial viability of the facility. In the financial community, the need for capacity is typically not highly considered in evaluating a merchant plant's economic viability, rather the generation and earnings profile for the facility is considered. If an independent power producer is able to demonstrate a firm contract for a facility, particularly a long-term contract, the risk associated with that independent facility will be reduced resulting in greater ability to obtain debt and possibly lower debt rates. Note, contract will typically have a fuel escalation clause or a parallel fuel purchase agreement to limit the risk associated with generating costs increasing to levels above the power purchase price. Overall, the carrying costs of the facility will be reduced. To capture this, the sensitivity case capital charge rate (carrying costs) is lowered by 2 percent.

  On the buy-side, entering into firm power purchase agreements provides reduction of several costs, such as the capital investment in the facility, or potential risks, such as those associated with short supply in a period of price spikes. However, the fuel costs risks are typically considered a pass through and the risk of over-purchasing or purchasing at a too high price still exists. As such, the benefits and costs are considered to cancel out one another and no change from the Base Case is considered for the incumbent utilities. Overall, this case tends to make IPPs a more attractive source of generation.

  Although several alternative contract arrangements could exist and alternative requirements could be determined by the PSC, we consider only one case from the modeling and will draw conclusions for other potential contractual obligations from it.

- **Siting Limitation Cases** - Under our Base Case, we allow unlimited capacity expansion but allow the model to determine the least cost development option and area. To capture the impact on consumers of alternate limitations on siting within South Carolina, we examine three alternatives.

  - **Increasing Plant Development Costs**. Under the first alternative, the cost of developing units is assumed to increase considerably after the initial development of already planned units. This cost increase is associated with increasing infrastructure costs of adding units, for example, the costs to the developer of new units are expected to absorb additional costs to upgrade the transmission network to support additional builds or to hook to the gas network as sites move further and further away from the existing pipeline network.

  - **Maximum In-State Builds**. As mentioned, it is essential to consider not only the physical plant, but also the infrastructure supporting it when siting new facilities. Using the PowerWorld load flow model, we have estimated the maximum capacity that can be added to the grid without compromising the grid stability under Base Case growth conditions. This result was then used in IPM® as a limitation on the total capacity that could be constructed in-state.

- **No In-State Builds**. As an extreme case, ICF determined the total cost of service impact if neither utilities or merchants were allowed to add new capacity in-state through 2010.

REPRESENTATION OF THE MARKET USING IPM®

The Modeling Approach

To provide a perspective for the potential for energy growth, capacity requirements and infrastructure changes, ICF developed a model-based representation of the South Carolina electricity system using its proprietary IPM® modeling software. IPM® is a simulation model projecting wholesale market power prices based on an analysis of the engineering economic fundamentals. The model does not extrapolate from historical conditions but rather from given future conditions (new demands, new firm plants, new fuel market conditions, new environmental regulations), which determine how the industry will function. Specifically, the model projects plant generation levels (i.e., dispatch), merchant power plant revenues and costs, new power plant construction, mothballing, retirements, retrofitting, upgrades, fuel consumption, and inter-regional transmission flows. The model makes these projections by calculating production, and therefore production costs and prices, using a linear programming optimization routine with dynamic effects (i.e., it looks ahead at future years and simultaneously evaluates decisions over specified years).

This analysis treats South Carolina as having four individual transmission constrained sub-regions or marketplaces representing the major IOUs, Duke, Carolina Power and Light and South Carolina Electric and Gas, and the network of Cooperatives throughout the state. Each sub-region has a single clearing price in each hour set under perfectly competitive market conditions. We use this sub-region definition given that the South Carolina marketplace has some internal transmission limitations across control areas.

To account for the influences of interconnections with neighboring systems, we have also modeled almost the entire North American Eastern Interconnect subdivided into approximately twenty-five regional or sub-regional markets. Therefore, the forecast is part of a single, internally-consistent analysis that considers all interactions across the grid in all years.

ICF conducted a single expected market price case representative of our expectations for a Base Case market price. The purpose of the Base Case is to establish points of comparison for alternate scenario analysis. By comparing alternate forward scenarios, an explanation of how underlying assumptions such as transfer capability across regions, and alternate assumptions on key parameters such as demand can be determined. The remainder of this chapter will focus on Base and Sensitivity Case assumptions. The next chapter provides results of these cases.

The sensitivity case analysis will vary a number of parameters from the Base or Reference case, however, the general modeling structure across all cases remains the same and is presented in the table below.

Table 7.2: Overview of Modeling Framework

Parameter	Treatment
Economic Market Structure	Perfect Competition in Wholesale Markets
Expectations	Rational with foresight.
Transaction Type	Spot (transactions lasting one-year or less).
Internal Transmission	Four distinct markets are considered within South Carolina due to limitations on the existing transmission grid. Additional markets for merchant activity are considered.
Transmission Interconnects	Transmission transfer capabilities are taken from load flow analysis performed using the PowerWorld simulation model.
Natural Gas Pricing	Taken from analysis performed using the ICF NANGAS simulation model.
Retirements	Economic decisions are internalized.
Capacity Requirements	Minimum reserve requirements are modeled on a sub-regional level.
Unit Availabilities	Existing unit availability consistent with historical. New units assumed to operate at higher availabilities.
New Unit Characteristics	Technology gains are assumed to result in declining capital costs over time.
Transmission Tariff Structure	Less "Pancaking" Than Currently Prevails. Move to 10 individual coordinating organizations in the Eastern Interconnect.
Transmission Capital Investment	Assumed static in pricing analysis.
New Builds	Considers all units approved by the PSC at the time of this analysis to come on-line as planned.
Nuclear Capacity Factors	Consistent with historical generation averages.

BASE CASE MODELING ASSUMPTIONS

Specific assumptions considered in the Base Case are presented below.

Table 7.3: South Carolina Base Case Modeling Assumptions

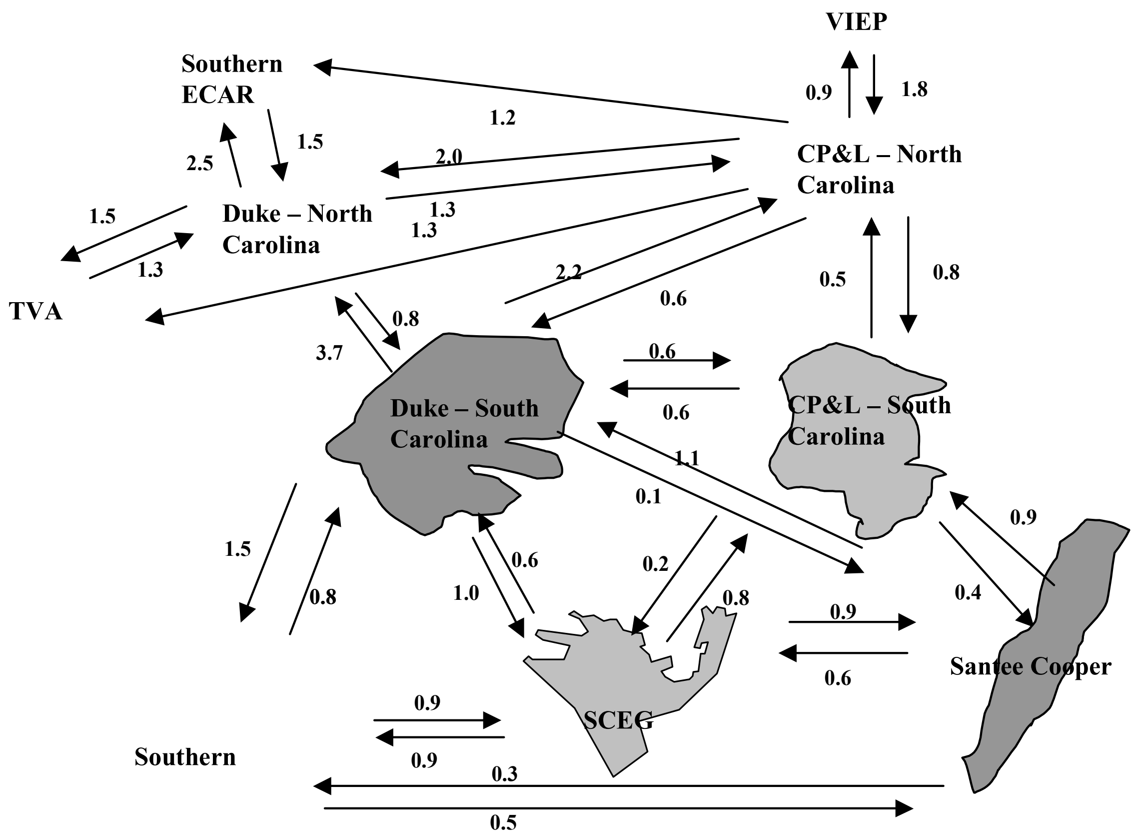
Parameter	Treatment – Base Case		
	Duke South Carolina	CP&L South Carolina	SCEG
2002 Weather-Normalized Peak Demand (MW)	5,606	1,491	4,517
2002 Net Internal Demand[1] (MW)	5,358	1,373	4,317
Annual Peak Growth			
2002-2005 (%)	3.09	3.09	3.09
2006-2010 (%)	2.83	2.83	2.83
2002 Weather-Normalized Net Energy for Load (GWh)	29,994	7,854	23,174
Annual Energy Growth			
2002-2005 (%)	3.25	3.25	3.25
2006-2010 (%)	3.03	3.03	3.03
Planning or "Market Revealed" Reserve Margin (%)			
2002-2010	15	15	15
Recently Operational Capacity 1999-2000 (MW)	--	--	55
Capacity Additions Currently Under Construction (MW)			
2003	640	550	450
Total New Construction 1999 – 2002	640	550	505
ISO Capital Cost (2000$/kW)	Combined Cycle	Combustion Turbine	Aero Derivative LM6000
2003	600	384	524
2005	600	384	524
2010	570	365	498
Fixed O&M (2000$/kW/yr)	20.7	14.0	15.3
Financing Costs for New Unplanned Builds			
Debt/Equity Ratio (%)	50/50	30/70	30/70
Real Debt Rate (%)	6.3	7.3	7.3
Real After Tax Return on Equity[2] (%)	11.2	11.2	11.2
Income Taxes (%)	38.3	38.3	38.3
Other Taxes (Duke (SC) CP&L (SC) SCEG[3]	2.8	2.8	2.8
General Inflation Rate	2.5	2.5	2.5
Levelized Real Capital Charge Rate	14.3	16.0	16.0
	CAPO (SC)	Duke (SC)	SCEG
Annual Average Delivered Gas Price[4] (2000$/MMBtu)			
2003	3.63	3.63	3.63
2005	3.86	3.86	3.86
2010	3.68	3.68	3.68
Delivered Gas Price Seasonality[5]– Differential from annual average (2000 $/MMBtu)			
Summer	-0.22	-0.22	-0.22
Winter	+0.46	+0.46	+0.46
Winter Shoulder	-0.05	-0.05	-0.05
Summer Shoulder	-0.25	-0.25	-0.25
Annual Average Delivered Oil Prices - (2000$)	Arab Light Gulf Coast ($/bbl)	Residual 1% ($/mmbtu)	Distillate ($/mmbtu)
2003	21.4	4.69	
2005	21.4	4.89	
2010	21.4	4.89	
Representative Minemouth Coal Prices (2000$/Ton)	Central Appalachia (1% S, 12,000 Btu/lb)	Central Appalachia (1.5% S, 12,000 Btu/lb)	
2003	26.1	24.6	
2005	22.2	21.7	
2010	23.3	21.5	

Table 7.3: South Carolina Base Case Modeling Assumptions (continued)

Coal Transportation Annual Real Price Decrease (%)	2.0				
Environmental Compliance Requirements	Already promulgated regulations.				
Transmission Tariff Structure	Less "pancaking" than currently prevails, e.g., less pancaking in the Midwest				
Nuclear Capacity Factors (%)	CAPO (SC)	Duke (SC)	SCEG		
2003	89	83	79		
2005	89	83	81		
2010	89	81	184		
Nuclear Retirements	End of nuclear operating license or based on economics. Assume extensions for all plants whether applied for an extension or not.				
New Unit Heat Rate[6] (Btu/kWh)	Combined Cycles	Combustion Turbines	Aero Derivatives		
			9,455		
2003	6,822	10,764	9,374		
2005	6,753	10,671	9,173		
2010	6,583	10,443			
Existing Power Plant Availability[7] (%)	Availability				
Coal Steam	84-86				
Oil/Gas Steam	83-85				
Minimum Turndown[8] (%)	Coal Steam		Oil/Gas Steam		
	40		25		
Variable O&M Range (2000$/MWh)[9]	CC	CT	Oil/Gas Steam	Unscrubbed Coal	Scrubbed Coal
	1.0-7.4	0.8-6.1	1.3-9.7	1.0-11.7	2.2-12.7

[1]Net Internal Demand is equal to peak demand less interruptible load.
[2]The nominal equity rate consistent with the real equity rate and an inflation rate of 2.5 percent is 14.0 percent.
[3]Includes property taxes and insurance costs.
[4]Includes commodity price and basis differential; reflects annual average across all hours of the year; the actual realized price applicable to individual plants in the region will vary depending on the hours and seasons of dispatch
[5]Summer: June, July, August; Winter: December, January, February; Winter Shoulder: March, April, October and November; Summer Shoulder : May and September
[6]ISO, HHV, Full load, degraded.
[7]Availabilities are an approximate value representing all units within the region.
[8]Turndown describes minimum level of reliable operation.
[9]Inversely correlated with capacity factor and is an output of the model.

Figure 7.3: South Carolina Transfer Capabilities (GW)



Transfer capabilities across regions were determined using the PowerWorld transmission simulation model. Note, for this analysis, all cooperative generating sources and demand levels are grouped together in the region labeled Santee Cooper. Further discussion on assumptions or results will use the Santee Cooper name to describe all cooperatives unless otherwise specified.

SENSITIVITY CASE FURTHER EXPLANATION AND ASSUMPTIONS

Analyzing sensitivity cases for the impact of alternate policy decisions, infrastructure change, or forward conditions was done as part of this analysis to determine policy recommendations adequate under a broad range of conditions. The analysis was done by varying assumptions from the Base Case and will show the sensitivity of power pricing to consumers and costs to generators. The key adjustments by case are described in more detail below.

RTO Policy Implication Cases

As a result of FERC's initiative to establish large regional transmission organizations, there are several uncertainties about the role between state's jurisdictional authority and the regional process. This uncertainty applies not only to the siting and maintenance of transmission facilities, but also applies to siting of generating facilities. In order to capture the impacts on South Carolina of alternate formations of larger regional RTO organizations, we have modeled two sensitivity cases; the first considers an expansion of the ISO organization in the Mid-Atlantic

(Case RTO1) while the second considers the FERC large RTO proposal (case RTO2). Assumptions that vary for these cases are described below.

Transmission Sensitivity Cases

The transmission infrastructure of the electric network serves as the backbone of the entire market. Since the transfer capabilities on any network can fluctuate dramatically based on current system conditions such as the load and generation levels at particular spots, it is important to consider the native transmission infrastructure and possible variations that may occur on the system. The Maximum In-State Builds case described above combines a transmission sensitivity with a cost of building scenario. In addition, we have examined two extreme transmission isolation cases to provide an outer bound on expectations for changes in costs to South Carolina generators and consumers.

Alternate Demand Growth

One of the critical driving factors of long-term power price movements is associated peak demand growth. Minor changes in weather conditions can result in significant changes in the peak load requirement in any given year. In the Base Case, the ICF demand growth forecasts is initially based on the rolling average of the 10 year annual average growth rate since 1970. Over time, we assume a gradual decline from this long-term historical level. Although this is reasonable, a second scenario was examined to determine the sensitivity of prices to the demand level. Rather than run an extreme case in either direction, ICF prepared a case to reflect a reasonable growth assumption.

Table 7.4: VACAR Demand Growth Assumptions (percent)

Region	Base Case		Alternate Growth Rate Case	
	Peak Demand	Energy	Peak Demand	Energy
Duke				
2003-2005	3.08	3.25	2.53	2.50
2006-2010	2.83	3.03	2.53	2.50
CP&L				
2003-2005	3.08	3.25	2.53	2.50
2006-2010	2.83	3.03	2.53	2.50
SCEG				
2003-2005	3.08	3.25	2.53	2.50
2006-2010	2.83	3.03	2.53	2.50
Santee Cooper				
2003-2005	3.64	3.42	3.72	2.87
2006-2010	3.25	3.16	3.72	2.87
Virginia Power				
2003-2005	3.64	3.42	3.72	2.87
2006-2010	3.25	3.16	3.72	2.87
Total VACAR				
2003-2005	3.29	3.31	2.98	2.64
2006-2010	2.99	3.08	2.98	2.64

Our Alternate Demand Growth Case utilizes the annual average historical growth rate from 1993 through 1999 by utility as calculated from the FERC Form 714 load filings. In the long term, the same Base Case trend is applied to the FERC Form 714 historical growth.

Environmental Control Policy Sensitivity

In addition to the general analysis showing impact of alternate policy states or potential for price volatility, ICF has also examined the general impact to generation owners in South Carolina of the promulgation of stricter environmental pollution control standards. Our analysis compares a status quo situation to a case based on the Clear Skies Initiative. Under Clear Skies, SO_2 and NO_x regulations become tighter than current levels and mercury (Hg) standards are initiated.

CHAPTER EIGHT: MODELING SCENARIO ANALYSIS AND POTENTIAL IMPACTS

This chapter provides a comparison of results from the Base or Reference Case to the alternate sensitivity cases.

Table 8.1: Investor Owned Utilities Components of Price, 1995

Price Component	Cents/kWh	Million Dollars	Percent of Total
Production	***4.71***	***107,191***	***66%***
Purchased Power[1]	0.53	12,131	7%
Fuel	1.27	28,992	18%
Non Fuel O&M	0.76	17,184	11%
Capital Related	1.87	42,638	26%
A&G Allocation	0.27	6,245	4%
Transmission	***0.51***	***11,620***	***7%***
O&M	0.09	2,151	1%
Capital Related	0.39	8,822	5%
A&G Allocation	0.03	647	0%
Distribution	***1.91***	***43,470***	***27%***
Total Price	7.13	162,281	100%

1. Net of wholesale revenues.

Source: Derived from FERC Form 1 filings for 1995. Reported in Office of Policy CECA Supporting Analysis.

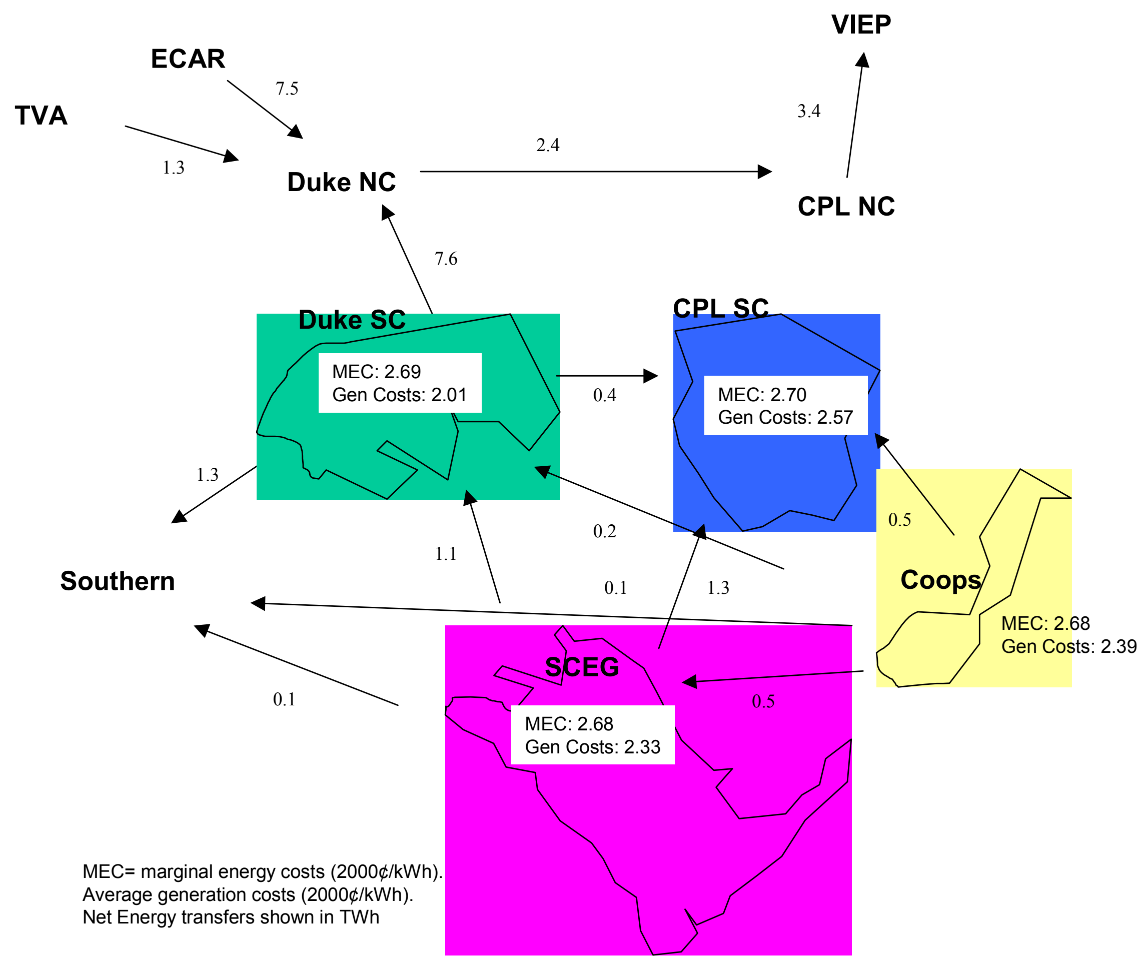
As shown above, production and transmission charges account for nearly 75 percent of total costs. We assume that no change in distribution costs would occur as a result of the sensitivity analysis. We also do not consider A&G costs directly in this analysis, but do not consider them a large or volatile contributing factor to prices. As such the relative change from the Base Case represents the total change in incremental costs required from the Base Case, i.e., there is no consideration of sunk costs. However, the Base Case pricing presented does not represent a full price to consumers or full cost to generators.

Note that all references to Santee Cooper in the results discussion are intended to indicate the entire cooperative market rather than Santee Cooper in isolation.

BASE CASE RESULTS

The Base Case represents a reasonable expectation of forward power market conditions and is considered as a reference case to compare to alternate sensitivities for an impact analysis. The figure below provides a snapshot of the 2005 Base Case results we will focus on. The three items we show are marginal energy costs – representing the competitive price for power purchases and sales in the wholesale markets; production costs – representing the costs of generating electricity to the system providers; and energy transfers – total sales and purchases across systems.

Figure 8.1: Base Case 2005 Results - Marginal Energy Costs, Production Costs and Net Energy Transfers



As can be seen, a diverse set of power transactions occur with energy movement occurring within South Carolina, within utility operating territories crossing state borders, and across borders between other reliability areas such as Southern and ECAR. The revenue expectations based on the marginal energy costs are similar on a per kilowatt-hour basis and little variation exists in regional pricing. However, a greater variation exists in per kilowatt-hour generation costs.

Table 8.2: South Carolina Regional Production Costs (2000¢/kWh) – Base Case

Region	Year					Levelized[1]
	2003	2004	2005	2008	2010	
CAPO-SC	2.61	2.59	2.57	2.52	2.49	2.55
Duke-SC	2.05	2.02	2.01	2.01	2.00	2.02
SCEG	2.27	2.35	2.33	2.29	2.42	2.32
Santee Cooper	2.11	2.30	2.39	2.68	2.82	2.46
Merchant	5.27	4.56	4.34	3.93	3.96	4.42
Weighted Average	2.25	2.31	2.33	2.39	2.45	2.34

Note: Represents major components of power generation costs including fuel, O&M, and investment capital.
1. Levelized values represent the annuity value at an 11.2 percent real discount rate.

Generation costs presented do not include general and administrative costs, annualized capital expenditures from existing units or depreciation, but are representative of the majority of costs of generation including fuel, variable and fixed O&M, and investment capital. On a per kilowatt-hour basis, the generating costs are quite similar in all regions with the exception of the merchant plants. The higher per kilowatt hour cost results not only from the use of gas, but many of the units operate only as peakers and have very little generation, thus distributing operating and maintenance costs over a very small amount of generating hours. Additionally, the units operate seasonally in periods of higher fuel prices and have relatively high heat rates.

Table 8.3: Base Case Select Generation Costs by Region (Millions of Dollars - Real 2000)

Region	Year					Levelized[1]
	2003	2004	2005	2008	2010	
CAPO-SC	169.6	170.4	168.4	166.9	166.2	168.2
Duke-SC	874.0	864.5	865.9	847.5	839.6	858.0
SCEG	543.2	571.5	616.3	642.2	743.1	614.0
Santee Cooper	517.1	593.1	638.3	776.0	848.2	672.9
Merchant	160.1	202.8	223.2	233.9	227.8	207.3
Total	2,264.0	2,402.3	2,512.1	2,666.5	2,824.9	2,520.3

Note: Represents major components of power generation costs.
1. Levelized values represent the annuity value at an 11.2 percent real discount rate.

Although merchant total costs increase over time, their generation also increases resulting in lower real per kilowatt-hour costs over time. Costs in SCEG and the Santee Cooper/ Cooperative areas are expected to increase at faster rates than costs in the South Carolina areas of Duke and CPL due to expectations for capacity expansion. Note, Duke and CPL total system costs would be increasing at rates similar to SCEG and Santee Cooper given capital investment in the North Carolina market.

Table 8.4: Base Case Wholesale Revenues (Millions of Dollars – Real 2000)

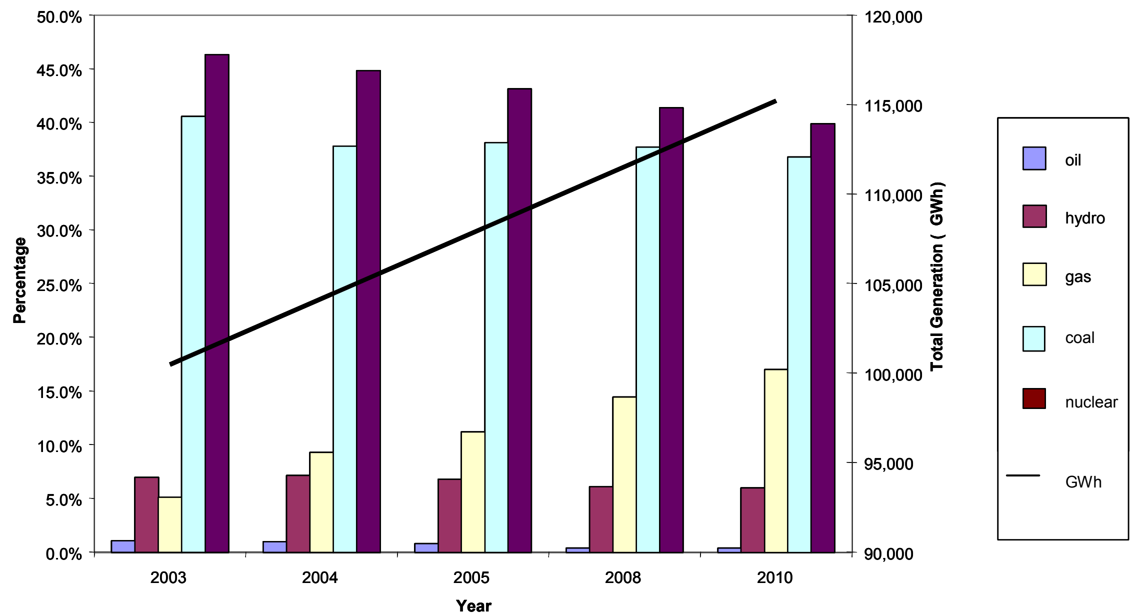
Region	Year					
	2003	2004	2005	2006	2008	2010
CAPO-SC	242	311	340	346	689	356
Duke-SC	1,384	1,660	1,744	1,732	1,950	1,800
SCEG	796	1,165	1,103	1,107	1,334	1,366
Santee Cooper	839	1,614	1,656	1,717	1,870	1,931
Merchant	201	312	350	335	365	363
Total	3,461	5,062	5,192	5,238	6,207	5,817

Note: Firm power prices are the total of the marginal hourly energy generation cost plus the costs associated with maintaining reliable supply resources.

The values presented in for Wholesale Revenues are indicative of the revenues for wholesale market energy sales that would be earned by the utility for energy and capacity sales. Thus these values represent total wholesale market revenues. Note, a given facility will receive the market price only in hours it is operating. As such, a peaking facility operating in relatively few hours will realize a higher average price than will a combined cycle operating in baseload and mid-merit hours, although it's total revenues may be lower.

In the near-term, it is expected that merchant generators will have the highest marginal costs. Overtime, regional/owner type price variations diminish as the long-run marginal costs of electricity are driven by natural gas at both the utilities and the non-utility areas. As such, we do not anticipate that a more favorable cost structure for consumers can be realized in the generation market through differentiation of utility or non-utility builds in siting policy requirements.

Figure 8.2: South Carolina Projected Generation by Fuel Type as a Percent of Total Generation – Base Case



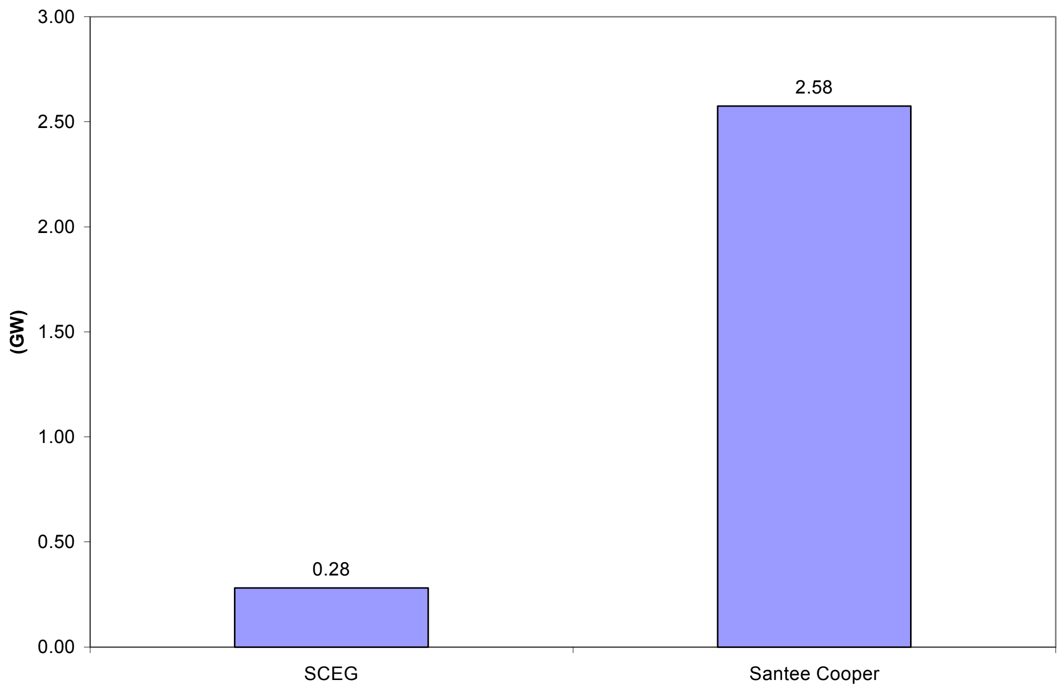
Over time, we expect that coal, nuclear and hydro generation will remain relatively flat. However, as energy demand continues to grow, these baseload generation sources will become a smaller and smaller percent of the total generation in South Carolina. Through 2010, total in-state generation is expected to grow 2 percent per year on average. In contrast, generation from gas-fired resources is expected to grow about 20 percent per year on average.

Under our Base Case, energy requirements in the state are expected to grow by 3.1 percent annually through 2010. In part, this additional requirement is met by increased generation at existing units, decreasing energy sales to external sources, and by additions of new capacity.

In the Base Case, unplanned capacity additions in South Carolina are about 2.9 GW by 2010. SCEG and Santee Cooper (all cooperatives) are the only two regions that build, with 90 percent of the capacity additions occurring in Santee Cooper. The capacity expansion is considered necessary to maintain adequate reliability margins.

Capacity additions are expected to be required as early as 2004 to support cooperative load growth.

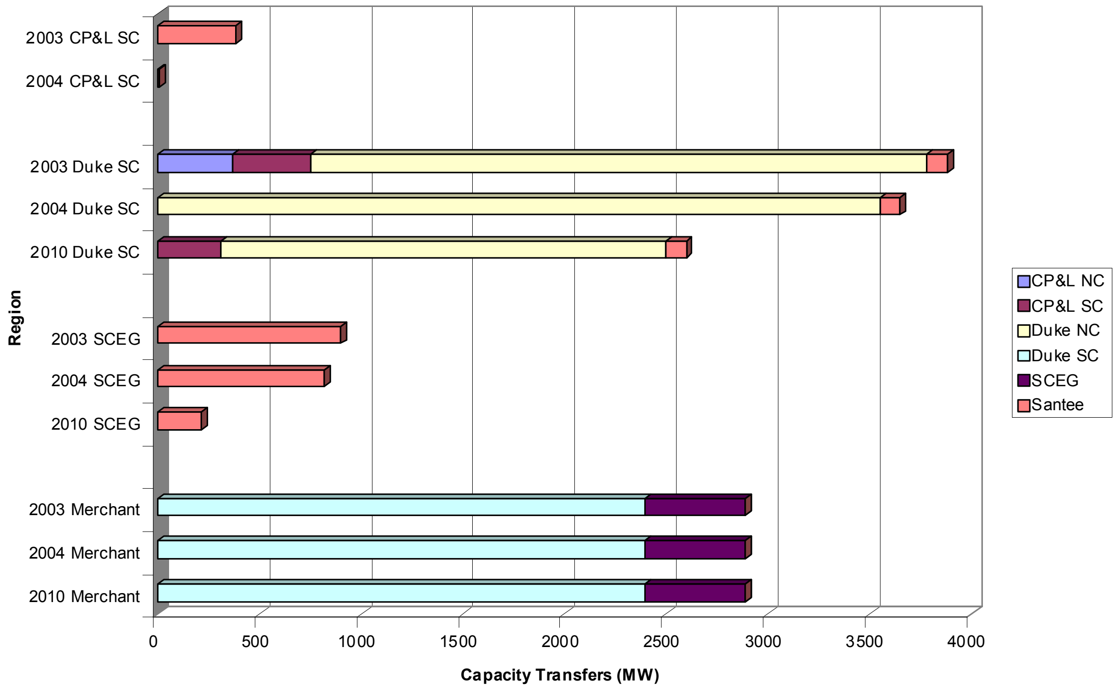
Figure 8.3: South Carolina Capacity Additions by 2010 – Base Case



Peak period capacity requirements reflect the value of adding new units to the grid to support reserve margin requirements. In addition, capacity transfers with external regions may also supplement capacity at peak hours.

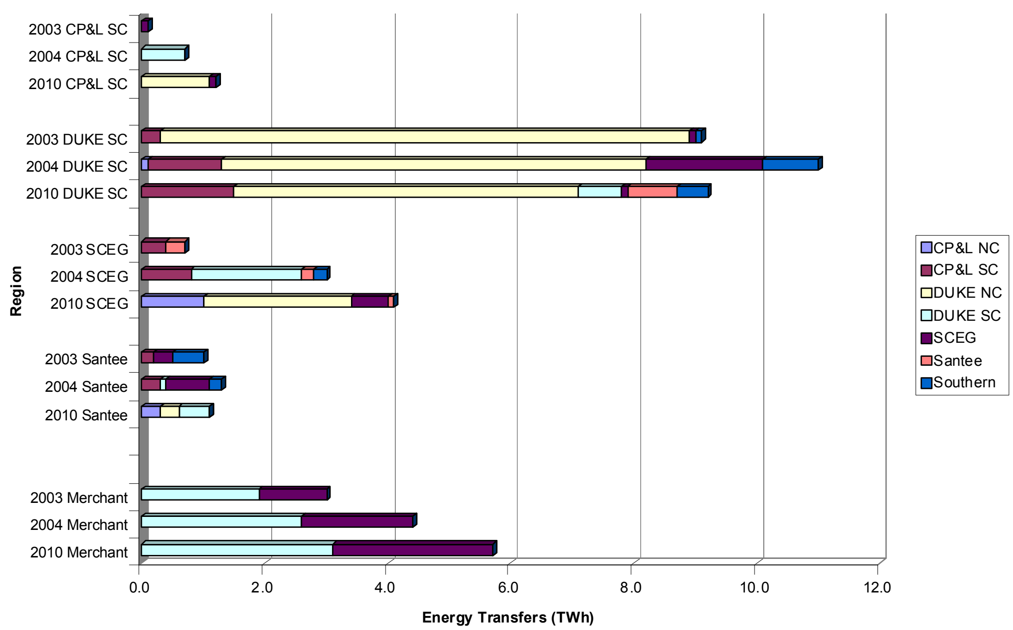
With the addition of several merchant and utility facilities in the near-term years, South Carolinians have expressed a concern about building capacity and polluting the local environment to support the capacity needs of others. The Base Case analysis finds that South Carolina is a net exporter over time, but more due to demands from other remote states, rather than to demands from Duke and CPL control areas. We find that capacity trades at peak are generally limited to intrastate, or intra-control area transactions.

Figure 8.4: Base Case Peak Period Net Capacity Exports from South Carolina



To some extent the limited demand for resources at peak is reflective of a broad overbuild in the near-term market throughout much of the Eastern Interconnect. In the long-term, regional diversification is expected to be reduced as gas-fired capacity becomes the fuel of choice. As such, opportunity for economic trading across regions is reduced.

Figure 8.5: Base Case Net Energy Sales from South Carolina



Similar to the sales at peak, the South Carolina Duke area and the merchants in South Carolina are the largest sellers of energy in the remaining year. The Duke area has the largest excess available, however, most of this generation is routed to the customer base in North Carolina within the Duke service territory.

OVERVIEW OF SENSITIVITY CASE RESULTS

Table 8.5: South Carolina Utility (IOU) Generation Costs by Select Case (Million US $)

Year	Base Case	FERC RTO	Contractual Obligations	Isolation
2003	1,587	1,587	1,587	1,473
2004	1,606	1,585	1,606	1,488
2005	1,651	1,624	1,651	1,521
2006	1,617	1,623	1,618	1,537
2008	1,657	1,713	1,658	1,583
2010	1,749	1,774	1,671	1,649
Levelized 2003-2010	1,640	1,649	1,631	1,540
Percent Change from Base	N/A	+1%	-1%	-6%

Note: Includes CPL South Carolina, Duke South Carolina, and SCEG.

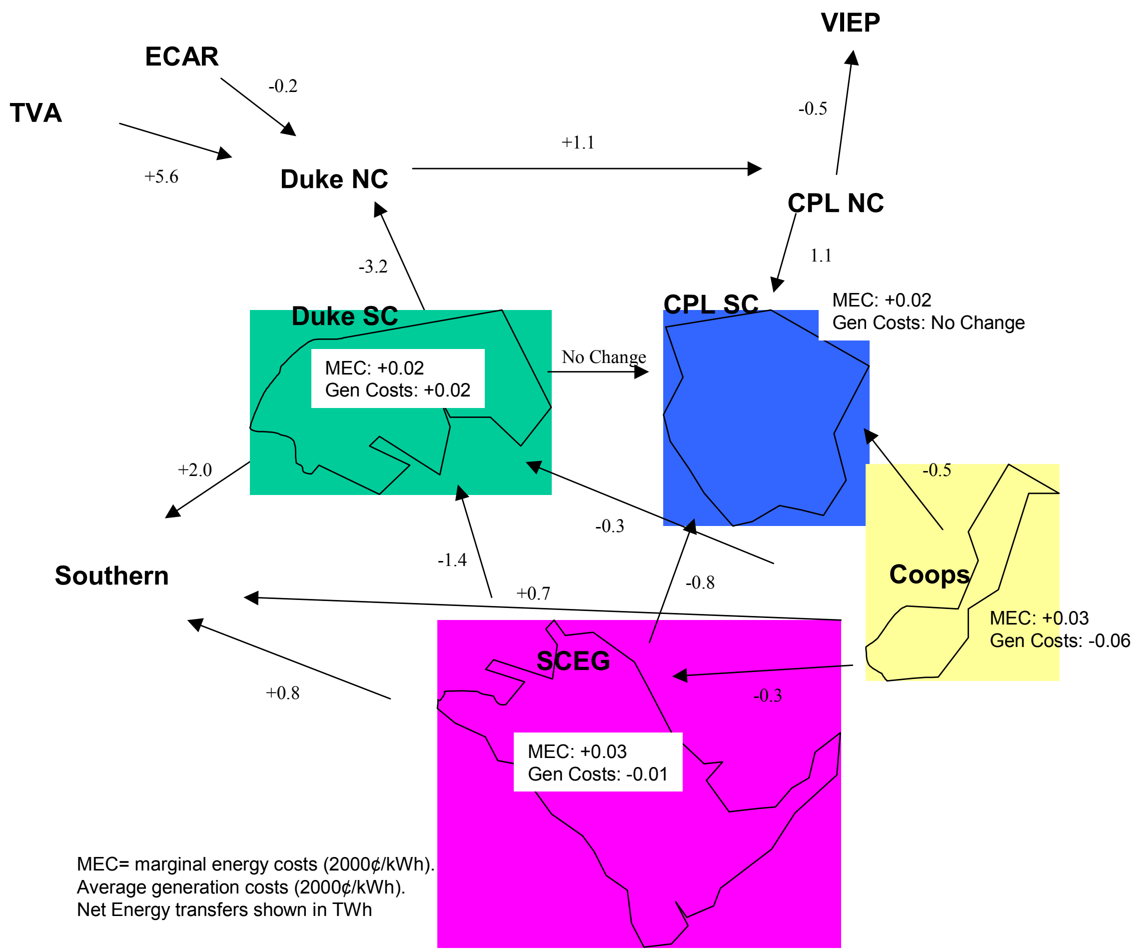
Several cases examining potential policy rulings have been examined to determine the impact of alternate decision structures on overall costs of generation to South Carolina. In general, we see little change in costs to the incumbent utilities.

- The FERC RTO case results in lower costs in the near-term as the RTO structure is implemented. However, over time, costs are expected to grow.
- Requiring merchant plants to have firm long-term power purchase agreements in place would result in an overall lower cost to the incumbent utilities in the near- and mid-term. However, long-term risk (not shown here) becomes greater as the potential error around forecasts supporting original agreements tend to be larger.
- The isolation case represents an extreme scenario where South Carolina is completely isolated from the rest of the Eastern Interconnect. Under this scenario, the South Carolina utilities are able to reduce generation costs under this case as generation is limited to in-state end-use. However, revenues are considerably reduced as facilities may be idoled. Any out-of-state exports are presumably profitable and can lower ratepayer costs.

Below, we present more detailed results for these and several alternate sensitivity cases.

RTO POLICY IMPLICATION CASE RESULTS

Figure 8.6: FERC RTO Case Change from Base Results, 2005 - Marginal Energy Costs, Production Costs and Net Energy Transfers



Again, a snapshot in time is shown to represent the change in results from Base Case expectations due to implementation of the large regional RTOs proposed by FERC. Note, this case does not assume any potential savings from demand savings programs or improvements in unit efficiencies and availabilities. In this analysis, changes in production costs and marginal prices are minimal in 2005, however, transactions with TVA and Southern do change significantly with South Carolina overall importing more energy.

Wholesale power prices in South Carolina are expected to increase slightly as a result of a broader regional RTO policy. Most of this gain is in the value associated with reliability or firm capacity rather than with system lambda or marginal generation prices. Therefore, although costs may increase, it is possible that revenues also increase, leaving the utilities unaffected.

Figure 8.7: RTO Generation Versus Base Case

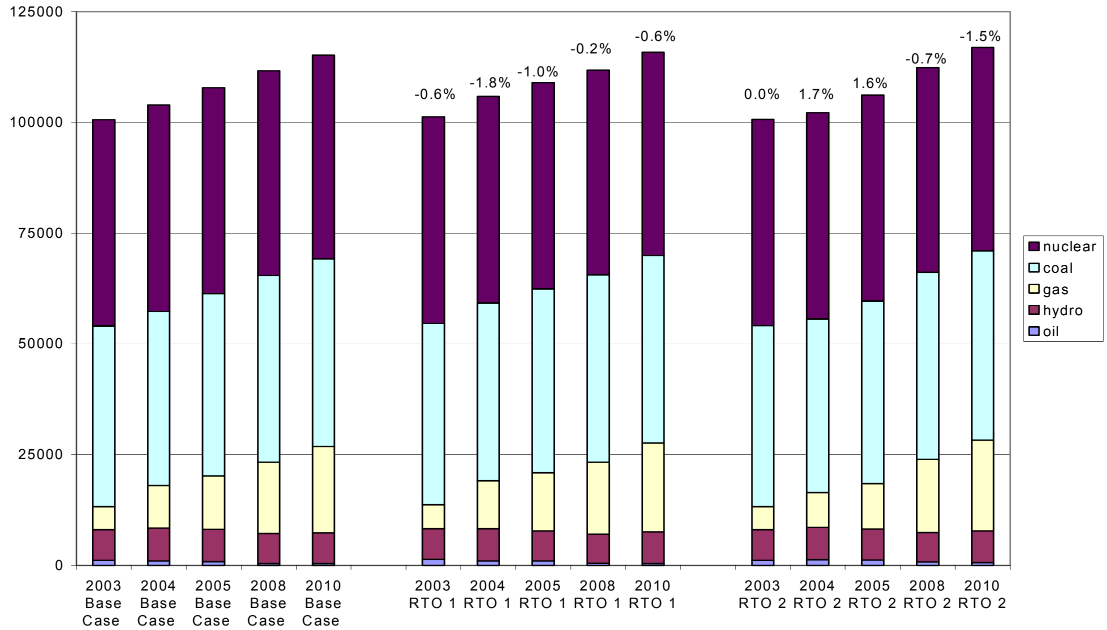
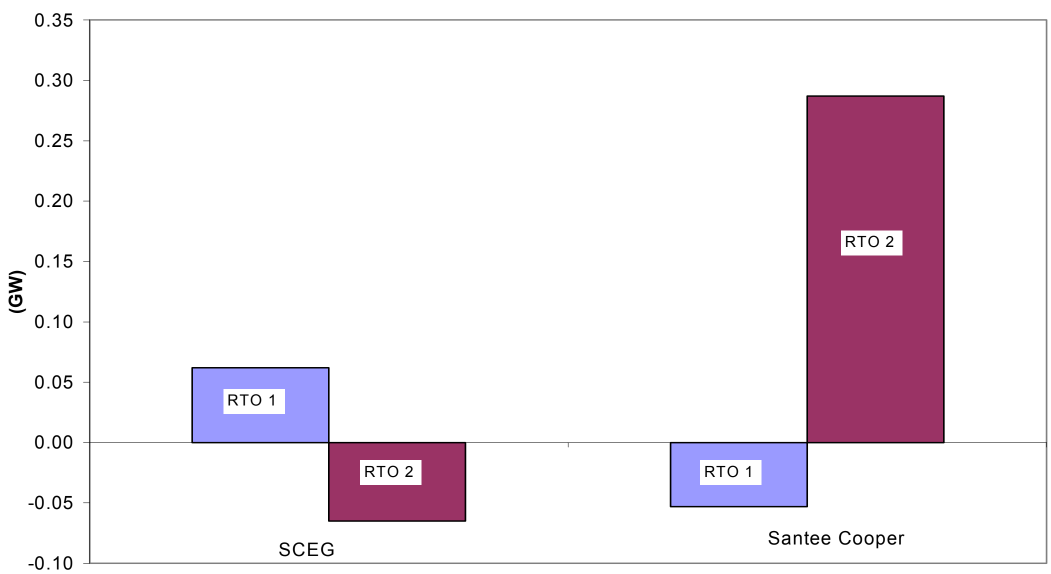


Figure 8.8: Change in South Carolina Capacity Additions by 2010



Changes in capacity additions in the RTO sensitivities only deviate slightly from the Base Case. SCEG and Santee Cooper remain the most desirable regions to build in. The Mid-Atlantic RTO case results in a switch of capacity additions between SCEG and Santee Cooper. However, the Large RTO case results in a small amount of additional megawatts (less than 300 MW) in Santee Cooper by 2010.

There is relatively little change in firm peak transfers in South Carolina between the RTO cases or from the Base Case. A more extensive change occurs in energy transfers which are presented below.

Figure 8.9: Net Energy Sales RTO Sensitivity Cases

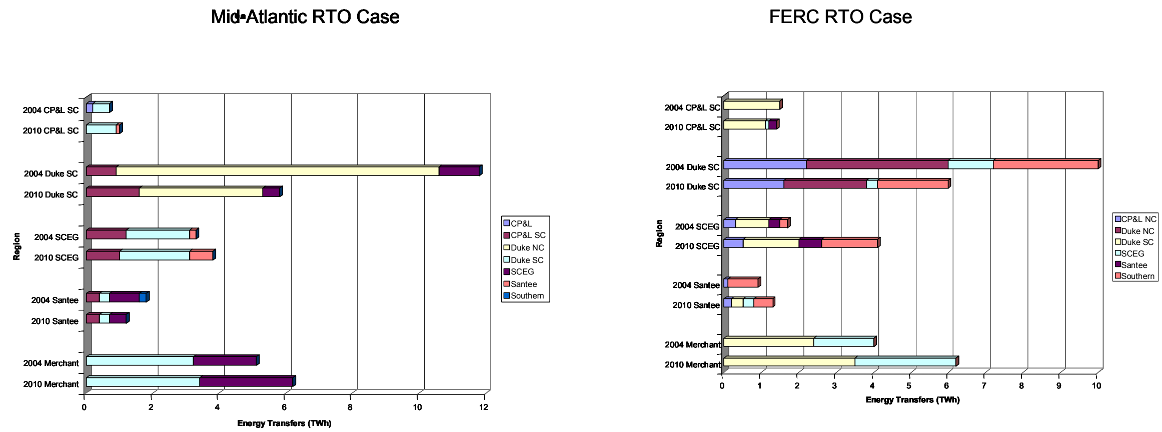


Table 8.6: FERC RTO Wholesale Revenues (Millions of Dollars – Real 2000)

Region	Year					
	2003	2004	2005	2006	2008	2010
CAPO-SC	293	553	370	460	386	356
Duke-SC	1,606	1,899	1,755	1,909	1,818	1,835
SCEG	924	986	1,095	1,216	1,517	1,538
Santee Cooper	1,003	1,513	1,654	1,827	1,856	1,917
Merchant	278	569	362	485	350	346
Total	4,104	5,519	5,237	5,898	5,927	5,992
Change from Base	19%	9%	1%	13%	-5%	3%

Note: Revenues are calculated as generation times the hourly wholesale power price.

Note, although generation costs are tending to increase in the FERC RTO case, revenues are also increasing for in state generators. This is true both for incumbent utilities, Cooperatives, and merchant generators.

Merchant Plant Contractual Obligation Case

Table 8.7: South Carolina Generation Costs (Millions of Dollars – Real 2000) – Merchant Contractual Obligation Case

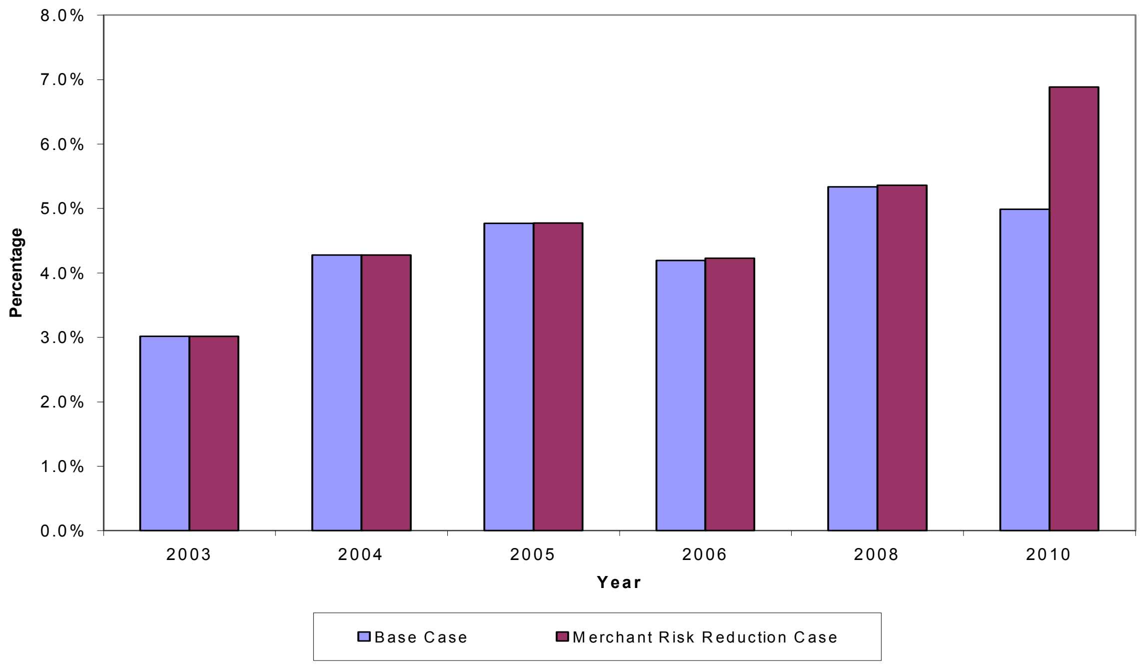
Region	Year				
	2003	2004	2005	2008	2010
CAPO-SC	169.6	170.4	168.4	166.9	166.2
Duke-SC	874	864.5	865.9	847.5	839.6
SCEG	543.2	571.5	616.4	643.5	665.6
Santee Cooper	517.1	593.1	638.3	776	848.7
Merchant	160.1	202.8	223.2	234.6	310.7
Total	2,264	2,402	2,512	2,669	2,831
Change from Base (%)	0.0	0.0	0.0	0.0	0.0

Note: Represents major components of power generation costs including fuel, O&M, and investment capital.

Although there is a slight decrease in the costs for incumbent utilities, overall, generator costs for the entire State are unchanged through 2010. However, the regulated utility costs are reduced as they experience cost savings associated with contracting. As more merchants find economic justification for bringing plants on-line in South Carolina, the merchant investment and overall production costs increase, however, this is in proportion with the costs saved by the utility by contracting rather than constructing own units.

The greatest change expected from this case would not be until after 2010 when more significant amounts of new capacity are needed.

Figure 8.10: Contractual Obligations versus Base Case, Merchant Generation as a Percentage of Total Generation

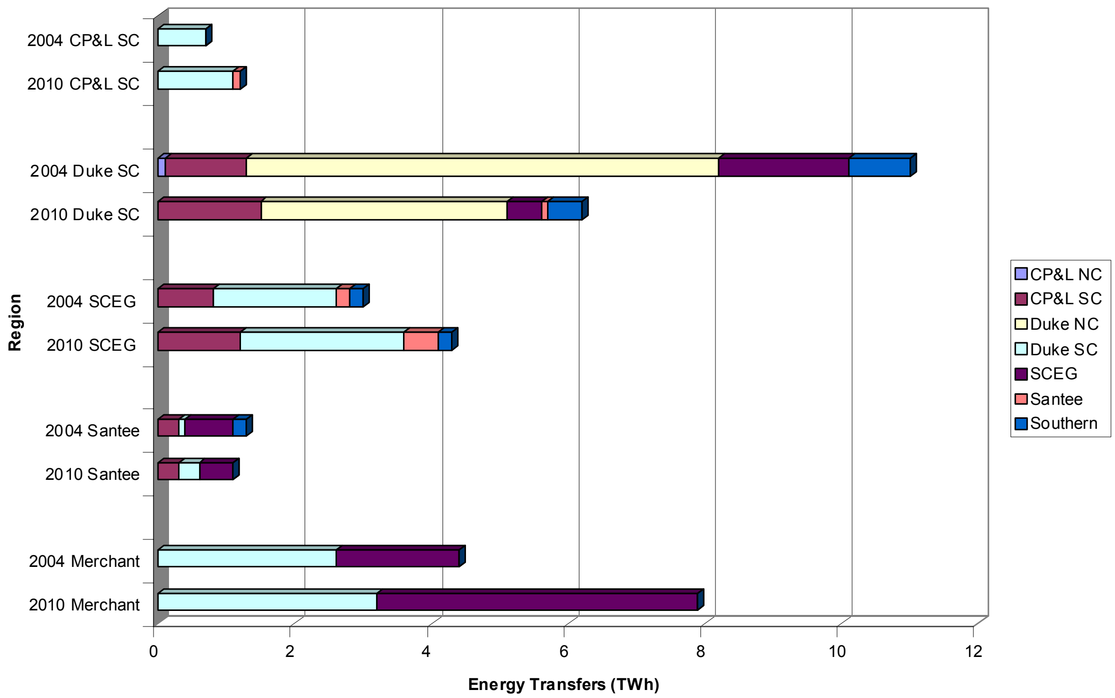


As a result of merchant plant additions, merchant plant generation increases very slightly in 2008 while it shows a more significant increase in 2010. Even with the additional capacity expansion that occurs in South Carolina, merchant generation accounts for a very small portion of total generation (less than 8 percent.)

Here rather than build in the utility areas, the preference is to build merchant facilities. However, the largest impact of this will not be felt until beyond 2010 when significant capacity additions occur.

In the Merchant Contracting Requirement Case total generation in South Carolina is very similar to that of the base case. However, by 2010, merchant generation becomes a larger percentage of total generation than in the Base Case.

Figure 8.11: Net Energy Exports (Sales) by Region/Utility – Merchant Contracting Case



In particular, we find that the SCEG region becomes a larger power importer from merchant facilities through 2010 rather than building new units. Impacts on other regions' energy sales and purchases are not as strong through 2010. The greatest impact of requiring long-term contracts is actually felt in the later forecast years (beyond 2010) when more significant capacity needs occur to match load growth. In the long-term, we would expect that merchant facilities become much more dominant as generation resources. Note, the long-term also contains the greatest element of uncertainty for the utilities who purchase from the merchant plants in that the forecast basis for the original contract negotiations has a higher margin of error associated with it.

Siting Limitation Cases

Counter to intuition, depletion of sites resulting from the possible "cherry-picking" of the most preferable site options does not result in a higher wholesale power price in the state of South Carolina. Rather, prices remain relatively stable and display a mild decrease from the Base Case.

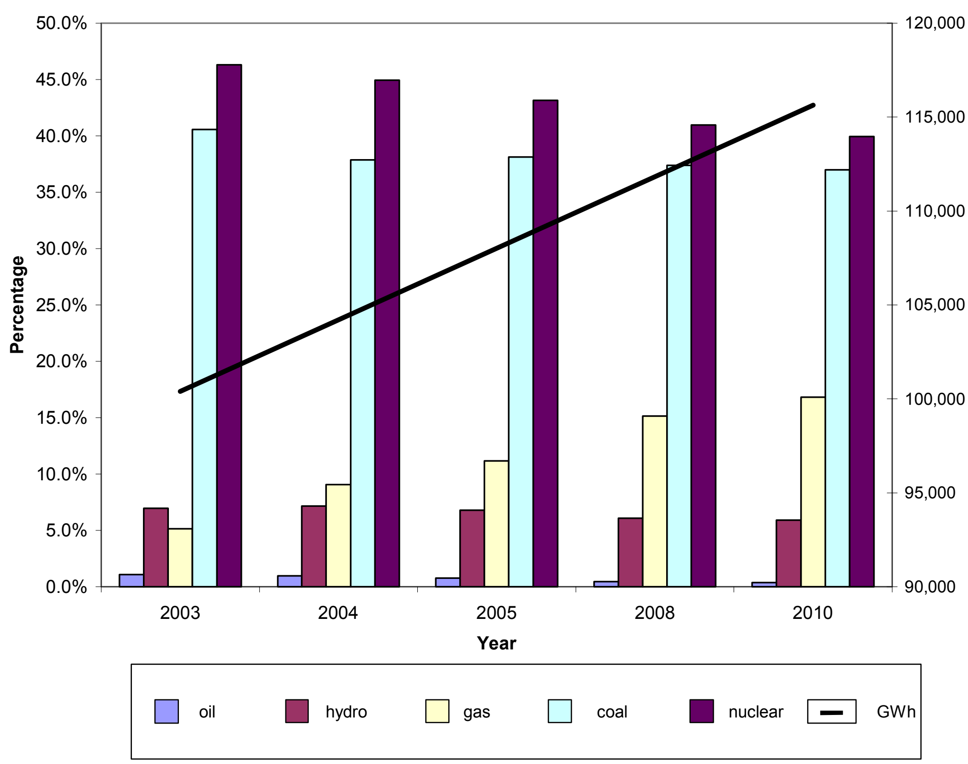
Table 8.8: Development Site Depletion Case South Carolina Generation Costs (Millions of Dollars – Real 2000)

Region	Year				
	2003	2004	2005	2008	2010
CAPO-SC	169.6	170.4	172.6	171.1	170.8
Duke-SC	874.0	864.5	865.9	839.7	801.7
SCEG	543.2	571.5	616.3	683.0	658.5
Santee Cooper	517.1	593.1	712.9	926.9	1,334.4
Merchant	160.1	202.8	223.1	236.1	777.5
Total	2,264.0	2,402.3	2,590.8	2,856.8	3,742.9
Change from Base (%)	0%	0%	3%	7%	33%

Note: Represents major components of power generation costs including fuel, O&M, and investment capital.

NO IN-STATE BUILDS

Figure 8.12: South Carolina Projected Generation by Fuel Type as a Percent of Total Generation – No In-State Builds Case



In the No In-State Builds scenario, energy requirements that were met by unplanned builds in the base case are now met by existing gas fired generation primarily in the merchant regions SCEG and Santee Cooper. Generation patterns in Duke and CP&L are unchanged.

This scenario makes use of the capabilities to purchase firm megawatts and spot energy from other regions. Under this scenario, the typical roles of North and South Carolina are reversed as North Carolina becomes a supplier to South Carolina. In this scenario, if no further expansion of the transmission grid with neighboring states occurred, there would be capacity shortages by 2010 that would grow significantly over time.

MAXIMUM IN-STATE BUILDS DUE TO TRANSMISSION INFRASTRUCTURE

ICF examined the possibility that the transmission grid could become a limiting factor in siting new generation capacity. Our findings show that at a 2.5 to 3.0 percent state-wide demand growth rate, South Carolina could add at approximately 3 GW of new generation above current levels without experiencing major congestion on the existing transmission network.

As such, South Carolina would not be able to expand in-state capacity beyond roughly 2007 to 2010 without also investing in the transmission grid. This case is less extreme than the No In-State Builds Case above, but it is indicative of the necessity for a wider view than need and environmental issues when siting new power generation facilities.

Transmission Sensitivity Cases

Table 8.9: Transmission Sensitivity Cases South Carolina South Carolina Generation Costs (Millions of Dollars – Real 2000)

Region	South Carolina Total Isolation				South Carolina Partial Isolation			
	2003	2005	2008	2010	2003	2005	2008	2010
CAPO-SC	166.2	158.3	166.5	165.4	169.0	168.2	166.2	391.4
Duke-SC	825.6	835.5	833.4	825.5	874.6	864.9	939.6	801.9
SCEG	481.2	527.3	582.7	657.8	541.9	608.8	743.0	919.0
Santee Cooper	490.1	537.1	643.6	760.9	570.4	649.5	865.0	1,437.4
Merchant	90.6	118.4	194.4	241.2	161.2	226.7	228.6	409.5
Total	2,054	2,177	2,421	2,651	2,317.1	2,518.1	2,842.4	3,959.2
Change from Base (%)	-9%	-13%	-9%	-6%	2%	0%	7%	40%

Note: Represents major components of power generation costs including fuel, O&M, and investment capital.

The transmission sensitivity cases show the significance of the multi-state service territories of Duke and CPL. In our first case, South Carolina is completely isolated from the rest of the Eastern Interconnect. Generating resources can be used within the state only. This results in a large excess of capacity in South Carolina. It is not until 2010 when significant load growth occurs to result in new build requirements. As can be seen, the cost of production is significantly reduced, as would be revenues. Note, this case is not considered likely, but was intended to show an extreme potential for change from the Base Case.

The second transmission sensitivity case represents a more reasonable market scenario in that it does not limit the connections within the Duke and CPL service territories, although no transactions with the Southern Region through South Carolina transmission lines are allowed. In contrast to the case showing extreme isolation, this case results in significantly higher prices in the near-term, resulting from the outflow of capacity from South to North Carolina.

In the very near-term, North Carolina has a high demand for capacity in the peak hours, but only limited capability to import power. As such, in the Base Case, the South Carolina regions were serving as a pass-through or highway regions to North Carolina. Purchases from the Southern

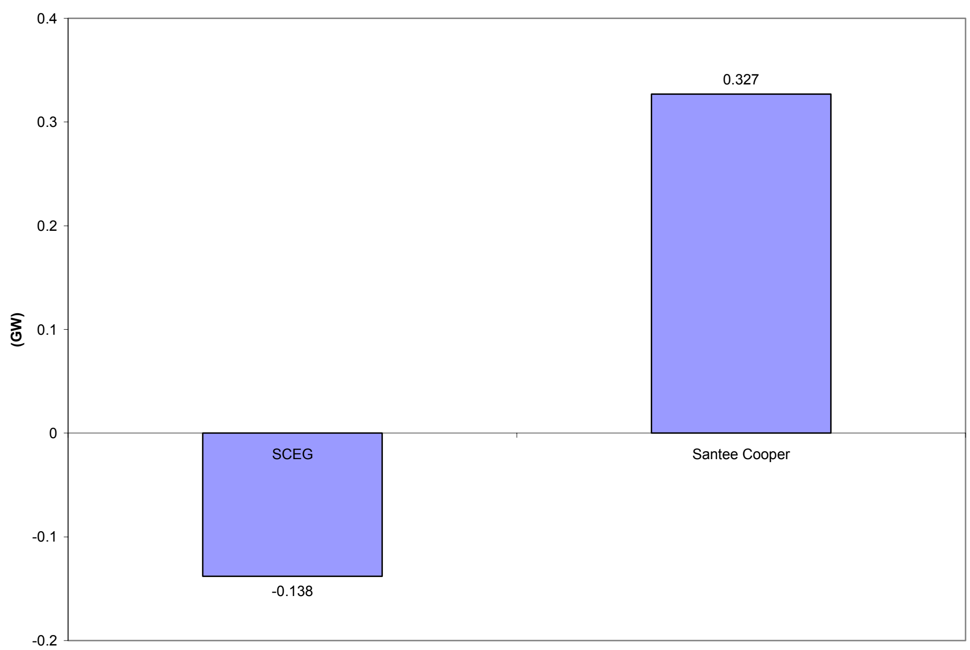
Region were funneled into North Carolina to meet peak demands. Through isolating the Southern region, the available capacity to move to North Carolina is reduced by significant enough amounts as to increase the willingness to pay for reliable supply to high price spikes. Thereafter, prices return to more normal levels as adequate supply is available to serve the combined North and South Carolina areas.

The extremes shown in these two cases also provide insight into the volatility of electricity pricing. Minor swings in available capacity or in transfer capabilities could result in significant upward or downward pressure on prices. Similarly, changes in demand growth or weather conditions could result in price volatility.

Note, under this scenario, the production costs for merchant generators increase significantly on a per kilowatt-hour basis as the peaking units operate in much fewer hours than in the base case and therefore distribute the total variable and fixed costs over a very limited number of hours. Over time, production costs for the cumulative merchant facilities decrease as their capacity factors increase. In other regions, the costs of production tend to go up over time consistent with the Base Case trend.

Alternate Demand Growth

Figure 8.13: Alternate Demand Growth Case Cumulative Capacity Builds through 2010 by Region

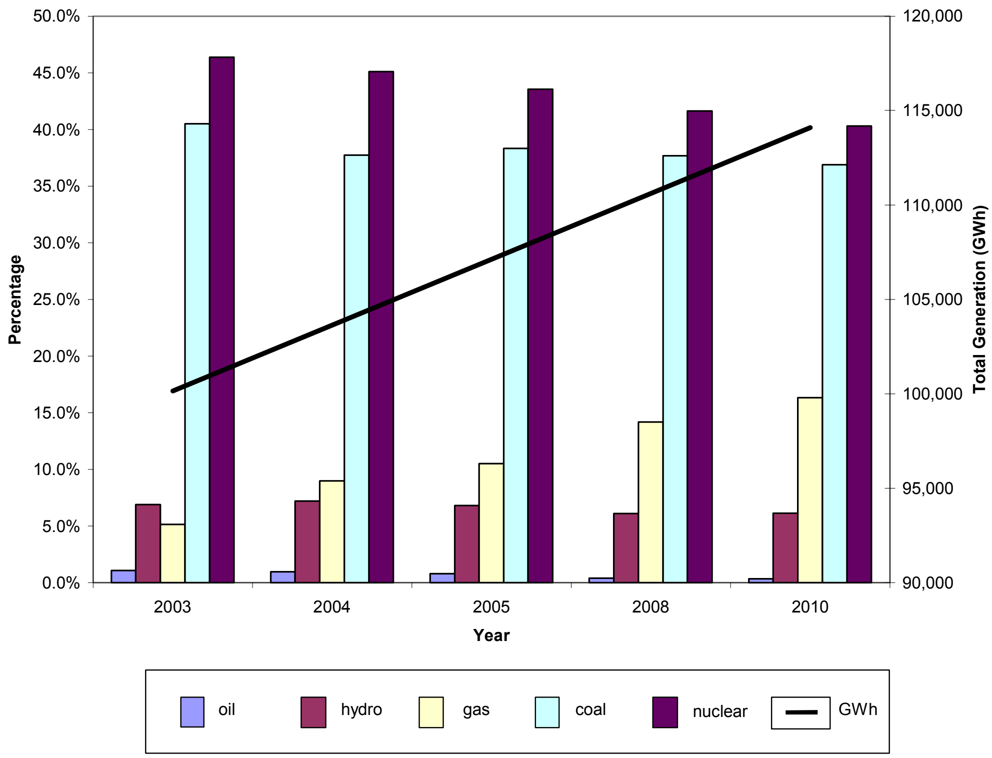


The alternate demand growth case captures a lower rate of growth in the utility service territories than in the Base Case, however, a higher rate is associated with rural and cooperative load growth. Growth rates used in this case are consistent with historical reported growth on the FERC Form 714 between 1993 and 1999.

As a result, unplanned capacity additions in SCEG are 0.14 GW less than the Base Case, whereas in Santee Cooper, unplanned capacity additions increase by 0.33 GW.

This scenario demonstrates the importance of regional load areas and the distribution of power facilities throughout the state to serve load. The Santee Cooper region (all cooperatives) exhausts its ability to purchase from others in South Carolina in the mid-term and has only very limited external transmission connections. As such, it must either build new capacity or contract with other suppliers to supplement load growth and serve demand. As a result, we see an increase in production costs in Santee Cooper while the remaining regions are relatively unchanged.

Figure 8.14: South Carolina Projected Generation by Fuel Type as a Percent of Total Generation – Alternative Demand Growth



With less aggressive demand growth rates in the alternative demand growth case, total generation in South Carolina by 2010 falls by 1 percent. However, increases in energy requirements are still met by increased gas generation.

Environmental Control Policy Sensitivity

In addition to the general analysis showing impact of alternate policy states or potential for price volatility, ICF has also examined the general impact to generation owners in South Carolina of the promulgation of stricter environmental pollution control standards. Our analysis compares a status quo situation to a case based on the Clear Skies Initiative. Under Clear Skies, SO_2 and NO_x regulations become tighter than current levels, and mercury (Hg) standards are initiated. As the strictest of standards under Clear Skies will not be enforced until beyond 2010, we present a long-term outlook in this case than for other cases.

We assume that under Clear Skies an alternate allocation of allowances will be in place once the program is active.

The SO_2 allocations for 2000 and 2010 in the Reference Case are consistent with the Environmental Protection Agency (EPA) Technical Documentation for the 1998 Reallocation of Allowances.

- In the Base Case, this allocation scheme is continued throughout the long-term.
- In the Clear Skies Initiative (CSI), the 2010 and 2018 allocations are based on the current 2010 allocation (8.872 million tons) and ratioed downward to match the CSI caps of 4.5 and 3 million tons in 2010 and 2018 respectively. As such, the distribution of allocations remains unchanged, however, the total amount of allocations declines.

NO_x allocations for the SIP Call are consistent. However, an annual NO_x constraint is introduced under Clear Skies. Annual NO_x was based on the expected 2004 emissions level of each plant. The CSI cap of 5 million tons per year nationally was ratioed to the 2004 expected emissions level and allocations were assigned to each plant accordingly. In 2008, the target rate drops to a total of 2.1 million tons, and further drops in 2018 to 1.7 million tons. Allocations in these later years have the same distribution as in the initial years.

Similarly, mercury allocations were based on expected 2004 mercury emissions and adjusted them to current emission levels of 48 tons. Mercury restrictions fall to 26 tons in 2010 and 15 tons in 2018, allocations were redistributed according to these caps in the later years.

The impact of the Environmental Control Policy Case is felt to the greatest extent at existing generation owners with unscrubbed coal power plants. In terms of cost of overall generation, the Clear Skies tends to have a leveling effect on the South Carolina traditional utility regions versus the merchant owners given that the merchant facilities are fired by relatively clean natural gas and tend to have pollution control equipment already installed.

On average, marginal energy prices increase roughly 1.6 percent from the Base Case between 2006 and 2010. Prices further increase in the long-term with tighter compliance standards, between 2006 and 2029, marginal energy prices are anticipated to increase by 3.1 percent on a levelized average basis.

As mentioned, the greatest impact will be felt on the unscrubbed coal generators that will be required to install pollution control equipment, purchase allowance, or modify generating patterns to reduce emissions. We present the impact of asset value on coal plants by owner below.

Table 8.10: Change in Value of South Carolina Coal Assets

Region	Change in Value of Coal Assets in South Carolina		
	Scrubbed	**Unscrubbed**	**Total**
Carolina Power and Light (South Carolina)	N/A	-44%	-44%
Duke (South Carolina)	N/A	-54%	-54%
SCEG	-2%	-9%	-8%
Santee Cooper	0%	-10%	-3%
Total South Carolina	0%	-16%	-9%

The implementation of a policy such as Clear Skies will be to force higher required recovery at the existing utilities in order to recover the costs of complying with tighter standards and the value lost at individual facilities.

CHAPTER NINE: CRITERIA FOR SITING GENERATION PROJECTS

FINDINGS

- **South Carolina** – The South Carolina Power Plant Siting Act did not anticipate the potential for merchant power plants. Implicitly, it appears to have envisioned a continuation of their extant conditions in which need would be defined as meeting the firm demand of customers of a franchised, integrated utility. Off-system sales would have primarily been in support of lowering ratepayer costs. Accordingly, it has not been surprising that South Carolina's treatment of applicant merchant plants on such issues as demand and need has been non-standardized, non-explicit and ad hoc.
- **Merchant Plants** – South Carolina and other states have been facing a large demand for approvals of new merchant power plants. One indication of the national magnitude is that during the 1999-2004 period, using the most narrow definition of potential additions (already on-line or already under construction) the US will add 183,000 MW versus a peak demand of about 700,000 MW. Thus, to the extent that there are policy implications for ratepayers or other stakeholders, this issue could be important.
- **Resource Effects** – Since the addition of merchant power plants adds supply, lowers prices, all else equal, helps guard against unexpected shortages to some degree, provides taxes and jobs and entails no obligation on consumers, it appears the key policy issue is the extent to which these plants affect limited state resources or have others. We focused in on four issues: environmental, electricity transmission, siting of future plants by incumbent suppliers, and natural gas.
- **Natural Gas Plants and Environmental Effects** – Thus, far the overwhelming majority of merchant plants are natural gas-fired. In the U.S., of the 183,000 MW identified above of additions, none are nuclear and only about 1,500 MW are coal-fired. All applications in South Carolina are for gas plants. Natural gas power plants are more environmentally benign in terms of land, water, and air emissions than coal fired plants. All plants must already comply with an array of local, state and federal pollution control requirements. Nonetheless, there is some incremental impacts on natural resources.
- **Electricity Transmission** – In the past, transmission impacts of new builds were less salient. Usually, the principal customers of the plant were known in advance and the builder was also the transmission system owner/operator. New plants were often accompanied by new transmission lines. Merchant power plants often do not know who their customers will be. This makes it difficult to purchase long-term transmission supply and/or justify new lines. Also, federal regulation has separated transmission from generation. New plants must be provided by transmission owners under FERC rules, and rights to firm transmission is on a first come first serve basis. Only states can block new additions; FERC still does not have federal eminent domain in power like it has in gas. To the extent that limited excess capacity is available, a merchant plant could obtain service at low cost while an incumbent utility would have to pay more since it was later or "lower in the queue." There is evidence that costs of hook-ups in PJM are rising for late comers. This appears to be the issue related to merchant plants identified to date. There is, however, complexities in this area. First, costs could rise and

then fall later as new plants are added, if the early plants by location or upgrades alleviate flow problems. Second, analysis is complicated by uncertainty in where new plants are being built, the huge geographic scope of the grid and the technical complexity of power flows which cannot be easily directed. Third, the institutional framework is very dynamic increasing concerns about transmission while complicating analysis. Fourth, the lack of transmission investment in the U.S. in some regions to match the generation capacity additions has created real fears of system deteriorization if not crises. Fifth, transmission policy is increasingly federal and regional, and will require increased coordination.

- **Sites for Incumbents** – We found no evidence of limited sites for incumbents due to merchant activity, except for the resource issues noted: power transmission, gas supply, and environmental.
- **Natural Gas** – In the past, IRP gas plants had firm gas transmission and were dedicated via long-term power sales agreements to particular loads. New merchant plants rely more on short-term non-firm gas supply. Also, their fuel flexibility is limited by technical issues (they can only use premium high cost distillate oil rather than low cost residual oil). Environmental restrictions (often federal) and delivery issues (small tanks for oil storage). Accordingly, if gas infrastructure does not expand, other customers including incumbent utilities could see a higher delivered price if they do not have firm supply and or alternative fuel options. Also, similar to electricity transmission, incremental gas delivery costs can be lower for merchants. Since their could be a first come first serve element in FERC gas pricing policy. The first increments of supply could be at the low costs of increased compression, or at average tariff rates while later buyers may have to access gas via an entirely new line at higher incremental cost.
- **Policies in Other States** – In this very dynamic situation of federal deregulation and merchant power, states have a much greater diversity in their approach to siting than ever before. The approach falls into the following categories:

    - **Market** E**mphasis** – Many states have eliminated need as a criteria for approval, relying on the market to policy itself. These states are trying to encourage merchant plants since they have deregulated retail access. They are also relying on FERC driven market mechanisms to address transmission issues for power and gas. All states are subject to environmental controls on new plants and hence, there is little flexibility once needs are no longer considered for these states.
    - **Market Light** – Many regulated states have been ad hoc like South Carolina. It appears that when shortages of generation appeared likely, they approved plants. Now that shortages of generation are less likely, they are focusing on other issues and are attempting to develop new rules. We have found no states with an organized explicit procedure for determining:
        - **Need** – If indeed the market can allow too many merchant plants to be built, how much is too much? This would ultimately require a determination of whether some specific higher reserve level (e.g., 25 percent utility-wide, statewide, 25 percent region-wide, what region) vitiates the acceptability of additional projects or how to weigh evidence such as contracts.
        - **Electricity Transmission** – No central statewide or regional procedure appears in place in any state in which transmission adequacy for future incumbent builds is addressed. Either the regulators, the incumbents, and/or merchants would have to

address the effects of new builds on customer costs in a comprehensive manner.

- **Natural Gas Supply** – Similarly, no systematic statewide procedure is in place to track the availability of low cost investments of supply, reliance or non-firm gas supply and on fuel flexibility of gas units.
- **Contract** – Some states, notably Florida, require all new plants above 75 MW steam capacity to have power sales contracts with utilities. This can be extended to fuel supply as well as power sales. The virtue of this approach is that analyzing power and gas transmission and need issues is a complex, resource intensive, imperfect science. It is also the most rigorous test of need and can be used to ensure all development explicitly for in-state ratepayers. However, it does discourage merchants placing more emphasis on the timely action of incumbents and regulators. Florida is adding capacity today, but has been one of the slowest to respond to the need in the 1990s for more units. It also stifles development of tax wide job producing activity. Also, it is very fact intensive in that there will still be judgments required about contract sufficiency (life of project versus ten years, for all or part of the output, contingent contract term evaluation, etc.). It also does not provide the collateral benefits of market light which provides information and a framework for regional and statewide action on critical issues such as electricity transmission infrastructure. Lastly, it is inflexibly in that if shortages unexpectedly emerge, contracts will be needed.

Recommendations

- Ultimately, the correct policy is a function of attitudes toward market forces and regulation in generation. If the state is comfortable with its regulation of incumbents, and wants to be as sure as possible that all development directly benefits in-state ratepayers, it can require contractual proof that the plant is selling firm to in-state end-users or their representatives and has firm supply for fuel. This approach is also relatively simple to implement. This approach lacks flexibility (e.g., let merchants build during periods of shortage), discourages industrial development, still leaves the state with the need to better track transmission issues and develop the capability to work regionally with RTOs to ensure grid adequacy. Hence, a market light approach, while more complex, could weigh contracts with other pieces of evidence. A market only approach seems inconsistent with the positive obligation to determine need, the fact that markets have periods of excess and shortages and the state emphasis on traditional regulation. This approach still leaves that state with the need to participate in regional RTOs and planning, to address transmission adequacy without any information, or systematic stateside procedure for assessing the situation.

Other Issues

Other issues that can be reviewed under the power plant siting process include those related to security. This area is relatively broad and can include measures associated with ensuring diversity of energy supplies, examining potential contingencies associated with locating at particular locations on the transmission or pipeline network, or requiring examination of potential emergency management issues within the siting review.

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